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Second Annual Clean Coal Technology Conference

Proceedings

Volume 2
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Objective

This Conference, co-sponsored by the U.S. Department of Energy (U.S. DOE) and the Southern States Energy Board (SSEB), seeks to examine the status and role of the Clean Coal Technology Demonstration Program (CCTDP) and its projects. The Program will be reviewed within the larger context of environmental needs, sustained economic growth, world markets, user performance requirements and supplier commercialization activities. This will be accomplished through in-depth review and discussion of factors affecting domestic and international markets for clean coal technology, the environmental considerations in commercial deployment, the current status of projects, and the timing and effectiveness of transfer of data from these projects to potential users, suppliers, financing entities, regulators, the interested environmental community and the public.

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Clean Coal Technology Deployment/Technology Transfer/Outreach Session

Panel Chair:
Ben Yamagata,
Executive Director,
Clean Coal Technology Coalition

COAL AND PUBLIC PERCEPTIONS

Remarks by

Robert C. Porter
Director of Communications
Office of Fossil Energy
U.S. Department of Energy

to the

2nd Annual Clean Coal Technology Conference

in

Atlanta, Georgia

September 9, 1993

I was scheduled to discuss the Department's clean coal outreach efforts. But perhaps -- rather than describing newsletters, publications, and things you can see for yourself -- it may be more useful for me to do some stage setting about why clean coal technology outreach must be an integral part of your role in coal's future.

I think -- as we spend our time at this conference hearing status reports about technologies -- it is important that we understand the significance of these advances not just in terms of hardware...but in terms of public perception.

And let me tell you right up front, I am a strong believer in four basic premises:

- (1) That coal is fundamentally important to this nation's future;
- (2) That, despite premise number 1, coal's future is by no means assured...and that for the last 10 years, coal has been losing ground...maybe following in the footsteps of nuclear power in the attitudes of the public;
- (3) That coal's future hinges on the public understanding and accepting the benefits of the technologies we are discussing at this conference. In my mind, public acceptance of coal hinges -- almost solely -- on the public's acceptance of advanced clean coal technology....

... not what happens in energy policy,
... not what makes sense economically,
... not what happens in world events.

But whether influential, local citizens understand and accept clean coal technology.

I think public survey data -- some of which I'll reference here this morning -- shows one very clear message: that it isn't coal's abundance, its relatively favorable economics, its domestic security, or even its impact on jobs that molds public opinion. It's the possibilities and potential for clean coal technology.

America's unique penchant for innovation, and America's continuing confidence in its scientists and engineers to solve seemingly intractable problems...that is the key selling point for coal. Everything else, in the long run, is secondary.

And Premise #4:

- (4) That public acceptance of clean coal technology is not going to be achieved through a nationwide advertising program run by the Federal government or even by the private sector. It is going to be gained at the grassroots level...one community at a time...one plant at a time...one referendum at a time.

The Federal government has neither the resources, the staff, nor the mandate to lead the charge in those debates. That is why I'm not sure a recitation of what we are doing in the Federal clean coal outreach program is all that important.

What is important is that the private sector step up to the plate...as individual companies and as individual citizens...perhaps coordinated nationally, certainly drawing upon a common base of nationwide experience...but nonetheless, working one-one-one at the community level...one customer, one civic club, one town meeting at a time.

A year ago, I would have told you that this is where I think the industry...from the production side through the transportation side to the end users...has let coal down...and let it down badly.

Coal producers historically have seemed only interested in mining and selling coal. Despite the herculean efforts of Dick Lawson and the Coal Association, domestic producers seem neither knowledgeable nor particularly interested in clean coal technology. Throughout the Clean Coal Program, it has seemed to us that the interest of the coal producer in this program largely ended at the rail tipple or the loading dock.

Throughout most of the Clean Coal Technology Program, the railroads didn't add much. For the most part, they seemed only interested in hauling coal....moving it from Point A to Point B. Once it got to Point B, whether clean coal technology was being used was someone else's concern.

The utilities seemed almost always to be sent out of the locker room and onto a playing field wondering why there was no one in the stands on their side of the field...no fans... no cheerleaders...not even a first-aid boy.

Now there were some very notable exceptions. In Ohio, Jackie Bird and the Ohio Coal Development Office were a breath of fresh air for clean coal technology. Open houses, educational efforts, and Jackie's own tireless energies have been exemplary...but unfortunately, the Ohio example has largely been the national exception.

And so, those who were in the Clean Coal game found themselves outmanned, outgunned, playing defense, and watching the 4th quarter clock tick away.

Today, however, for reasons I will explain in a moment, I have a slight glimmer of optimism that the coal industry -- the entire industry, or at least a good portion of it -- has recognized that a bad public image creates bad business prospects...for producers, for transporters, for end users. And bad business eventually leads to downsizing, layoffs or bankruptcies.

Coal has a serious public image problem -- how many speakers have you heard begin or end with that revelation? It should come as no surprise to you. And yet, I'm not sure the depth of that image problem is known or accepted by the coal industry.

I've heard some in the industry make this point -- or several variations of it: "The public doesn't like coal, but wait until the lights go out or the Arabs stage another embargo, or they find out that half of their county will have to be covered by windmills to do what a single coal plant will do...then they will come back to coal."

Ladies and gentlemen...it just won't happen.

Public concern about coal runs too deep...and it is important to understand that. Left unchecked, in my opinion, public sentiment will soon reach a point where coal will have to struggle simply to reach the rung of "fuel of last resort" on the public opinion ladder.

It is important for those who deal with coal...who make their livelihood from it...to get below the surface opinions and see the strong, countervailing set of tensions being created in the values of many Americans...the sense of what Americans believe is important.

Only then will you appreciate what coal is up against.

Let's start with those values...what matters most to Americans.

For 20 years, Cambridge Reports -- a polling firm out of Cambridge, Massachusetts -- has been asking the American people what are the most important problems facing the country.

Throughout much of the 1970s and into the early 1980s, energy dominated the response. In 1979, public concern about energy reached its high water mark. 70 percent of Americans polled ranked energy as the top national priority.

Today, even after a Persian Gulf War, energy doesn't even make the list. Less than 1 percent cite energy as a top national priority. Today's concerns are the state of the economy, the state of education (particularly primary and secondary education), crime and drugs, the rising cost of health care, and number five on the list, the environment.

In 1991 -- to give you some idea of how far energy has fallen -- Hart and Teeter Research conducted a poll for *NBC News* and the *Wall Street Journal*. They asked respondents to identify the nation's top three problems from a preselected list of eight. Education, poverty, and crime were the top selections. Environment was on the list.

Energy - despite a Gulf War that had ended a few weeks earlier -- wasn't even among the possible choices.

Americans clearly don't see energy security as a pressing national issue -- certainly not with relatively plentiful supplies and relatively stable prices. Nor, interestingly, do they seem to connect energy supply with economic growth.

Here is where I see a major disconnect in public awareness. There may be a dominating sense of public concern about the economy, about jobs, about improving the standard of living...but there seems to be no linkage in the public's mind between achieving these goals and the necessity of adequate, reliable energy. The two seem to be mutually exclusive.

There is, however, a clear linkage in the public's mind between energy and the environment.

Cambridge Reports, in the polls they have taken in the last 3 years, have reported a very fundamental change in public opinion. Ted Byers, a senior analyst with Cambridge, told a conference of clean coal project information officers last year that the change has been among the most "spectacular" -- his words -- as the polling service has seen.

It is the change in public attitudes toward the environment.

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In 1973, 34% of the American public wanted more environmental regulations. In 1990, 54% wanted it...a 20-point increase.

In 1992, by the way, even after passage of the Clean Air Act Amendments, two thirds of Americans believe that "more government regulation will be needed to solve pollution problems."

Now, some of the skeptics may be saying to themselves, "yeah, but once environmental control hits Joe or Jane Blow in the pocketbook, watch the attitude change." Here, the data is a little mixed.

Last year, even as the economy dominated the political agenda, a national poll asked about people's willingness to pay \$50 in extra taxes to solve specific environmental problems.

- o 78% said they would pay if extra taxes if they went to clean water programs.
- o 73% said yes if the funds went to clean up air pollution.
- o 71% said yes if the funds went to solar and wind power research.
- o 61% said yes if the problem was the greenhouse effect.
- o 59% said yes to help stop acid rain.

During the Clean Air Act debate, Cambridge asked the public if they supported cutting sulfur dioxide emissions in half by the year 2000 even if their electric bills went up by 10 to 15 percent. 74 percent said yes.

Another 1990 survey asked "Now suppose the price you pay for fossil fuels like coal, oil and natural gas had to go up to prevent global warming from having serious consequences, what is the maximum additional monthly cost you would be willing to pay?"

Nearly 30% pegged the range between \$5 to \$15 a month more. 28 percent said more than \$15 a month. Only 15% said they would be willing to pay nothing more.

The message: Americans seem willing -- within limits -- to put a price on environmental protection and to pay that price.

Now what does all this mean for coal and coal technology?

First, coal.

Americans seem to have two sides when it comes to coal. On one hand, the American public recognizes that coal play a role in meeting the nation's energy needs and even predict that it will play a greater role in the future.

Cambridge Reports found that three out of four Americans acknowledge that coal-fired power plants are a significant contributor to the nation's electric power supply. Three out of five predict coal-fired power plants will play at least an equally important role in the future.

That's the good news.

The bad news is that the American public prefers coal not be used.

In 1978, 55% of Americans supported the increased use of domestic coal. In 1991, that figure had declined to 39 percent. And when asked about more coal in their community, the number supporting coal drops to 27 percent.

Once a year Cambridge asks people what they think the nation's major source of energy will be in 25 years. Last year, 40 percent pointed to solar, while 31 percent -- interestingly -- said nuclear power. Only 3 percent said coal. And when Cambridge asked for their preference 25 years down the road, 58 percent said solar. Less than 1/2 of 1 percent opted for coal.

What are coal's strengths and problems?

Its strengths are cost and domestic security.

But far outweighing these are its problems -- air emissions first, mine safety a distant second.

As you might expect, acid rain dominated the air quality agenda in the 1980s, but also as you might expect, polls show that global warming is now supplanting acid rain as the most frequently cited environmental problem facing the nation.

Americans point to auto emissions as the primary cause of global warming, but air pollution from coal and other fossil fuel plants isn't far behind in second place.

And four out of five Americans believe the U.S. should take steps to prevent global warming even if other countries do not. And the majority continues to hold this view even when the prospects are raised of higher taxes and

placing U.S. businesses at a competitive disadvantage. In fact, two out of five respondents believe the U.S. should independently take steps to deal with global warming even if cost them their jobs.

That is how deep seated environmental concern has become as a core American value.

Now let's turn to what I believe is coal's last great hope - clean coal technology.

Here, there is public optimism for coal. But again, there is an upside and a downside.

Only a quarter of the population, according to Cambridge Reports, has heard about the efforts to develop clean coal technologies. That figure, unfortunately, has not changed much since 1989. Only one in five Americans believe the coal and electric utility industries have spent significant amounts of money on developing clean coal technologies.

Yet, two out of three Americans, when asked about the potential for new technologies for coal, are convinced that a concerted effort to develop and deploy clean coal technologies would improve the quality of the environment.

Americans seem to have an intrinsic faith in American ingenuity to solve conflicting problems. And even in light of the bad rap that American technology has gotten recently - 3-Mile Island, Challenger, Hubble, a lost satellite to Mars - Americans still hold out hope that its scientists and engineers, properly focused, can solve the environmental problems associated with coal.

The only major reservation is the fear that clean coal technologies will raise energy costs...but as we've seen, there appears to be some sentiment for moderate increases in costs if there is direct evidence that a cleaner environment will be the result.

So what does this mean for an outreach program for coal?

- (1) *First and foremost, it must focus squarely on the public's overriding concern about the environment.*

An outreach campaign rooted solely in coal's abundance, or as a counter to foreign sources of energy, or an instrument of national security is a campaign that will fall on deaf ears.

Ten years ago, Americans might have substituted domestic energy for decreased dependence on foreign energy, but today that tradeoff is much less likely.

Environmental concern is driving energy development attitudes. A coal outreach program must deal with environmental issues first...or the public will never hear anything else. And technology -- better technology, cleaner technology -- is what the public is pinning its hopes on.

- (2) Second, it is easy to say that Americans' fear of coal is fear rooted in misunderstanding.

Most Americans don't know where their personal electricity comes from. Coal plays a role, but they are surprised to hear the figure "56% of the nation's electricity comes from coal."

But it would be a serious mistake to think that the problems are entirely ones of lack of accurate facts. There is a question of performance. Americans have a love-hate relationship with their power company.

A 1989 Roper poll found that 92% of a national sample identified the "electric power industry" as either "absolutely essential" or "very important" to the country.

That same poll showed that "the electric company" ranked 4th in terms of excellence of service from a list of 12 types of services -- that included supermarkets, doctors, banks phone companies, department stores, credit card companies, mail order companies, and so on.

A 1990 poll asked "Which public utility in your area provides the best service?" 29% identified the electric utility, 19 points higher than the telephone company. Every other utility -- including, by the way, the gas company -- ranked lower.

Yet, Americans are convinced that the electric company cares very little about the environment and very little about their health and safety. As I said earlier, just one in five Americans believe the industry has spent a lot of money on developing clean coal technologies.

I know that I've given you a lot of facts and figures for so early in the morning, but I wanted to impress upon you one key fact:

That public concerns affecting coal and coal technology are so deep-rooted and systemic that they must be addressed at the grassroots level.

There is a certain allure to a nationwide television campaign -- following the footsteps of the gas industry, for example. But the challenge confronting coal is far different and much more difficult.

Contrary to gas, the coal industry must first reverse an overwhelming negative perception. It must build confidence in its commitment to the environment, to the health and safety of this and future generations.

The government -- even if we had the resources -- can't do that. We can produce information -- and we have done a lot of that in the last five years:

- o Nearly 100,000 copies of a primer on clean coal technologies distributed;
- o More than a quarter of a million copies of our "Dinosaurs and Power Plants" grade school educational package...and the demand is overwhelming our ability to deliver;
- o A new publication defining our strategic goals not only for clean coal demonstrations, but also for our R&D program...but produced in a graphic form that certainly breaks the mold of a typical government program plan. Its primary purpose: to visually attract readers who may not otherwise pick up a typical government publication;
- o Attempts such as the exhibits you see outside to reach non-traditional audiences who are, nonetheless, key decisionmakers.

But none of these activities conveys the fundamentally important message to the American people that those of you who produce coal, who make the equipment to burn it, and who extract electricity and energy from it are committed to this new environmental ethic.

That is something you must communicate clearly in simple ways -- with simple actions -- that consumers see and understand. The issue is largely one of trust.

There is a kind of dog-eat-dog attitude that has largely gotten coal into the fix it is in today...that has divided the coal industry and has contributed to lack of public trust and an increase in public suspicion about both the industry and the technology.

A year ago, I saw almost nothing that gave me much hope that would change. Today, I have changed my opinion. I see a glimmer of hope.

The coal industry - led by railroads, producers and others -- have come together to create the Center for Energy and Economic Development. With one major mission, to provide accurate information about coal.

The importance of this organization:

First, it is a coalition. The entire coal industry is beginning to unite. CEED is largely the outgrowth not of coal producers but of a railroad - CSX - who realized that its economic fortunes were tied inextricably to the fortunes of coal. When the Tallahassee clean coal project went under because of public pressure, CSX lost a major entre into a new, growing market. All of a sudden, it realized it, too, was part of the coal industry, and it too had a stake in reversing coal's bad public image.

Second, CEED is not going to be swayed by the allure of a glossy, national campaign. It is committed to working at the grassroots -- in areas where key decisions regarding coal are on the near-term horizon.

Third, CEED reflects the recognition that Government is not the only answer or maybe not even a major part of the answer to effective public outreach.

Government can provide public accountability for the tax dollars we have invested in coal and clean coal technology. We can announce results -- successes and failures. But it must be industry that builds the base of public confidence and trust that must exist between the public and those who produce, transport, and use coal.

Fundamentally, therefore, that is your responsibility and how successful you are, in my opinion, will determine coal's future in this country.



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EPRI OUTREACH PROGRAM APPROACH AND ACCOMPLISHMENTS

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**Thursday September 9, 1993
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Atlanta, Georgia**

EPRI OUTREACH PROGRAM APPROACH AND ACCOMPLISHMENTS

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Founded in 1972, EPRI conducts Research and Development activities on behalf of the Electric Utility industry in a wide range of activities. Since we are funded by over 700 member utilities, the challenge of delivery of that information to members is significant. Our outreach program is tailored to the industry, and uses traditional means such as printed media, as well as electronic media of all types. More and more the term delivery means working with the membership, to reduce the risk in early application of advanced technology. EPRI's participation in the DOE Clean Coal Technology program is reflective of that type of project, and represents a good example of participation in collaborative R&D. This paper supplements the Panel discussion on Clean Coal Technology Deployment/Technology Transfer/Outreach.

EPRI'S MISSION

The mission of EPRI has evolved from its inception in 1972, with much stronger emphasis now on application of the technology. It is insufficient to just develop the technology and publish a detailed technical report. Utility technical people are like most business people today, beset not by too little information, but by too much. Sorting out what makes sense for their companies in an industry that is seeing increasing change and competition is harder than ever. EPRI has revised its mission statement to reflect these changing needs. Our mission:

The mission of the Electric Power Research Institute is to discover, develop, and deliver science and technology for the benefit of member utilities, their customers, and society. (Emphasis added)

The term delivery was specifically added to recognize the need to do more than to invent a "better mousetrap". Much more emphasis has been placed on getting the technology used and that has, in turn, lead to a closer relationship with our customers, the electric utilities. Increasingly, this means EPRI involvement in application of the technology.

THE DELIVERY VEHICLES

Our mandate is to find the most effective vehicles to deliver the information developed in EPRI's research. We use the traditional research reports, seminars, symposia, and technical papers, but increasingly we are developing new means to accomplish this end. These include: computer programs, electronic network services, videoconferencing, application projects, loaned employees, and application centers with hotline services.

COMPUTER PROGRAMS

Over \$135 Million of EPRI research now results in computer software as a major product or the only product of research. This is not mass consumer-oriented software that provides calculation tools, but specialty software of all types, some of which requires significant training before the user is allowed to obtain the program. Several examples of this include Clean Air Technology (CAT) Workstation, FGDPRISM™ (Flue Gas Desulfurization Process Integration and Simulation Model), NOxPERT™ and FGDCOST™, all different types of software designed to transfer key information. Both FGDPRISM™ and NOxPERT™ are examples of software that consolidates a very large and diverse research program extending over many years, and provides a tool that facilitates use of the information. They represent different types of programs. CAT Workstation is a strategic planning tool designed to help develop or review compliance strategies. FGDPRISM™ is a first principles model of FGD system chemistry, that simulates the process, in order to avoid problems experienced in the early designs, and to improve operation, and NOxPERT is an expert system to optimize utility system NOx reduction strategies.

The CAT Workstation is designed to assist utilities in evaluating and updating compliance plans for SO₂ control. One of the major issues facing electric utilities worldwide is how to evaluate choices among different environmental control strategies or Clean Coal Technologies. The choice can be as "simple" as whether to scrub or switch, but in truth it is rarely simple. Today, dispatch, financing, emission allowance use and other decisions make multi-plant system compliance planning complex. Ideally, all possible scenarios would be evaluated and the optimum economic solution consistent with environmental constraints would be chosen. However, this can be an expensive effort due to the large number of options that have to be considered even for a moderate sized utility. This can literally run into trillions of cases when all options for compliance and systemwide changes are considered. EPRI has developed the CAT Workstation to assist U.S. utilities in performing these calculations on a multiple-unit-scenario basis.

The CAT Workstation allows any technology to be evaluated, with users creating detailed configurations of units, technologies, and fuels as needed. Many power plant units and strategies can be evaluated at once, with all necessary dependencies taken into account. Changes over time are factored into all

evaluations, including economic parameters, unit capacity factors, and emission constraints. The output of this workstation includes a list of technology-fuel combinations ranked by cost for specific units by time period, along with the number of allowances to buy or sell in each period.

The CAT workstation has an easy-to-use graphical user interface and allows users to access many of our other programs to support the strategic planning process with specific studies. For example, CAT can help screen FGD technologies, and then use FGDCOST input to develop site specific cost estimates and refine the decisions.

FGDPRISM™ is a process simulation model for wet limestone and magnesium-enhanced lime FGD systems. The program models desulfurization systems as a series of independent unit operations connected by process streams. For each unit operation, the model uses equilibrium, mass transfer, and thermodynamic principles to simulate the chemical reactions in that module and the resulting performance. The model is extremely useful in allowing utilities to investigate process or equipment modifications on existing FGD systems without the need for extensive, time-consuming full-scale tests. Also, the model can be used to evaluate or design new FGD systems. The model is complex and requires training prior to use, but it has proved powerful in numerous utility site applications. We are cooperating with DOE as part of the cooperative High Efficiency testing of utility sites to have FGDPRISM™ calibrated against utility sites so that it can be used to evaluate and predict performance of upgrade options at each site. It has proven successful commercially with licenses to designers of over 2/3 of the FGD Systems built worldwide, as well as a number of A/E and consulting firms. It is even being adapted for international use by utilities with PowerGen in the UK and Imatron Voima Oy (IVO) in Finland, each having licensed the program. We see this as an example of packaging the results of an immense R&D area with well over \$10M and 10 years of fundamental R&D, and creating a delivery vehicle that allows it to be used.

FGDCOST™ is a spreadsheet cost estimating model that planners and engineers can use to quickly obtain estimates of site-specific flue gas desulfurization (FGD) system costs. The model uses internally stored design information to enable users to readily estimate capital, O&M, and total levelized costs for both new and retrofit applications. The model computes costs by using site-specific data entered by the user and default values for the selected FGD process. User inputs revolve around economic criteria, boiler/coal characteristics, site conditions, and adjustments for retrofit difficulty.

Sensitivity analyses can be performed for variations in utility economic and design criteria, as well as site-related alternatives. Users will ultimately be able to download current cost information through the EPRINET™ Software Library for any of 28 FGD technologies. The new model released in August 1991, takes the place of RETROFGD, a computerized FGD cost estimating code released by EPRI in 1987. Several of the SO₂ Control technologies being tested under the DOE

Clean Coal program are included in the software, and users can incorporate the lessons learned during the demonstrations into their case studies.

The FGDCOST™ model gets around the technology transfer issue of the report not being tailored to the specific case. Generic cost estimates are published in our standard format, but the question always becomes how much will it cost for my situation. FGDCOST™ allows the customization needed to fit the site specific requirements, financial assumptions, size, sulfur content, load factor, etc.

NOxPERT™ is a model for screening NOx control technologies. Based on the best available correlations of NOx with fuel, boiler/burner type, and other combustion parameters, NOxPERT™ can be used to estimate NOx emissions for individual boilers, plants, and utility systems; identify the best combination of combustion NOx controls to meet emission reduction targets; and estimate the cost of NOx reduction retrofits. With a modest amount of baseline data, NOxPERT™ can provide emissions and cost estimates for boilers larger than 100 MW with +/-25% accuracy (and for smaller boilers with greater uncertainty).

Utility users can tailor NOxPERT™ to meet their individual needs by specifying the level of analytical detail and preferred emissions control strategy. For example, with minimal inputs, NOxPERT™ can estimate "as is" NOx emissions for initial emissions inventories. Users can then conduct preliminary assessments of NOx reduction options and costs using basic boiler design and operating data along with correlations relating NOx output to average parameters for each boiler class. These assessments can be refined by entering more detailed boiler design, operating, and cost data. The model can use any one of three NOx reduction scenarios when evaluating NOx compliance strategies: (1) the greatest NOx reduction option regardless of cost; (2) the least-cost option that meets a specified reduction level for an individual boiler; or (3) the least-cost options that meet a specified reduction level for all boilers in a utility system or pollution control district.

The systems being tested under DOE's Clean Coal Technology demonstrations are incorporated in the NOxPERT™ software, and updated results from the demonstrations should be able to be rapidly incorporated into the program.

These are but a few of the computer codes directly related to clean coal technology, but EPRI has developed data bases, expert systems, simulation models, and many analytical tools to provide the basis for application of research results.

ELECTRONIC NETWORK SERVICES.

EPRINET™ is an electronic network developed and implemented over the past several years by EPRI. It contains a variety of information and messaging services. The existing version of EPRINET™ has many information services available to users including messaging, news, resource catalogs, special interest

forums, file transfer services, a calendar of events, and directory. Version 2.0 is about to be introduced which is a state of the art system using new technologies to help EPRI and our customers be more productive. It will eliminate the dependence on mainframe computing and run as a set of client applications on each desktop environment (Windows or Mac) on a wide area network with services provided by multiple UNIX servers.

The value to the user is direct access both to EPRI expertise through electronic messaging and to the many resources available from EPRI.

One new use of EPRINET™ is PowerServe, a technology network developed by EPRI's Generation & Storage Division. PowerServe is a wide-area information service providing member utilities quick access to EPRI's growing list of advanced technology services being developed at regional centers throughout the U.S. PowerServe will supplement the basic services being provided by EPRINET. As EPRI moves toward a more regional focus to better serve its customers, PowerServe will offer expanded access to products and research results from its centers in manageable, task-oriented chunks. A consistent, easy-to-use graphical user interface that features on-line assistance and minimal training will help users understand and use existing products and will provide information about new products. PowerServe can reduce the delay, risk, and cost associated with the commercial introduction of advanced technologies at both existing and new power plants by quickly locating and applying the appropriate information and products.

In its pilot release, PowerServe will help fossil plant design, engineering, operations and control staff locate, interpret, and then apply the full measure of EPRI's technology and expertise in power plant engineering, operation, and maintenance. Later releases of PowerServe will provide a fully decentralized system of support and technology transfer services intended to serve a broad range of member utility personnel.

Powerserve will allow application programs resident on a variety of servers to be run by the utility user without the limitations of having to have the proper microcomputer setup, or making sure the software is current. For fast changing information or databases, it will provide instant updates. It can give access to real time information. This may well become a major conduit for EPRI to deliver information in the future.

VIDEOCONFERENCING

EPRI has installed videoconferencing centers in a number of our offices, test facilities and application centers. Videoconferencing for our overseas affiliates and cofunders provides a way to replace some of the travel involved in long distance technology transfer. Videoconferencing at the computer terminal is also being explored using new technology that is under development. We have used videoconferencing with numerous utilities to provide topical updates, advice prior to selecting emission control processes, and provide up to date reviews of ongoing projects prior to issuance of the final report.

APPLICATION PROJECTS

Our Tailored Collaboration (TC) program is a means to match specific utility R&D needs with EPRI's program. For up to 25% of a member's EPRI dues, the member can have specific R&D done by EPRI provided it matches the amount of dues used, by added cofunding. This halves the cost to the utility of research it would otherwise have to do outside EPRI. Projects in the NO_x, particulate, and SO₂ control areas are funded by TC. Many of the projects represent extensions of EPRI tools and information, but seek to answer the question, "...how can these address my problem"? By this means, we reduce the risk and help with the engineering and design decisions, as well as help avoid or solve problems in the initial installation. In turn, the extensions to applicability of these tools provide helpful information to EPRI's other member utilities.

APPLICATION CENTERS WITH HOTLINE SERVICES

In 1991, EPRI's Customer Systems Division established a new applications assistance center known as the Customer Assistance Center. Based on this successful model, the Environment Division has established an Environmental Assistance Center (EAC) in Dallas Texas. The EAC staff includes a hotline specialist, who has general familiarity with Environment Division results and resources, as well as technical staff to help in answering detailed questions, training, and jump starts. The commitment is to respond within 48 hours to any inquiry, and to follow up to determine if the request was satisfied with the information provided, and how the information was used.

Three services are offered through the EAC - Technical information via telephone, jump starts, and training and seminars. The technical information via telephone is accessed using a hot line answered during business hours, with a database used for tracking and follow-up. If our people on-site are unable to answer the questions, EPRI specialists will follow up. Jump starts are for more elaborate problems, where on-site assistance is required to solve the problem, often by applying EPRI results. An EPRI employee visits the site and works with utility staff to determine the best way to apply the R&D results. We then use a

pre-qualified group of EPRI contractors with a quick contracting mechanism to get the people on the job immediately. Training and seminars are typically conducted in small groups, often using special computer training facilities.

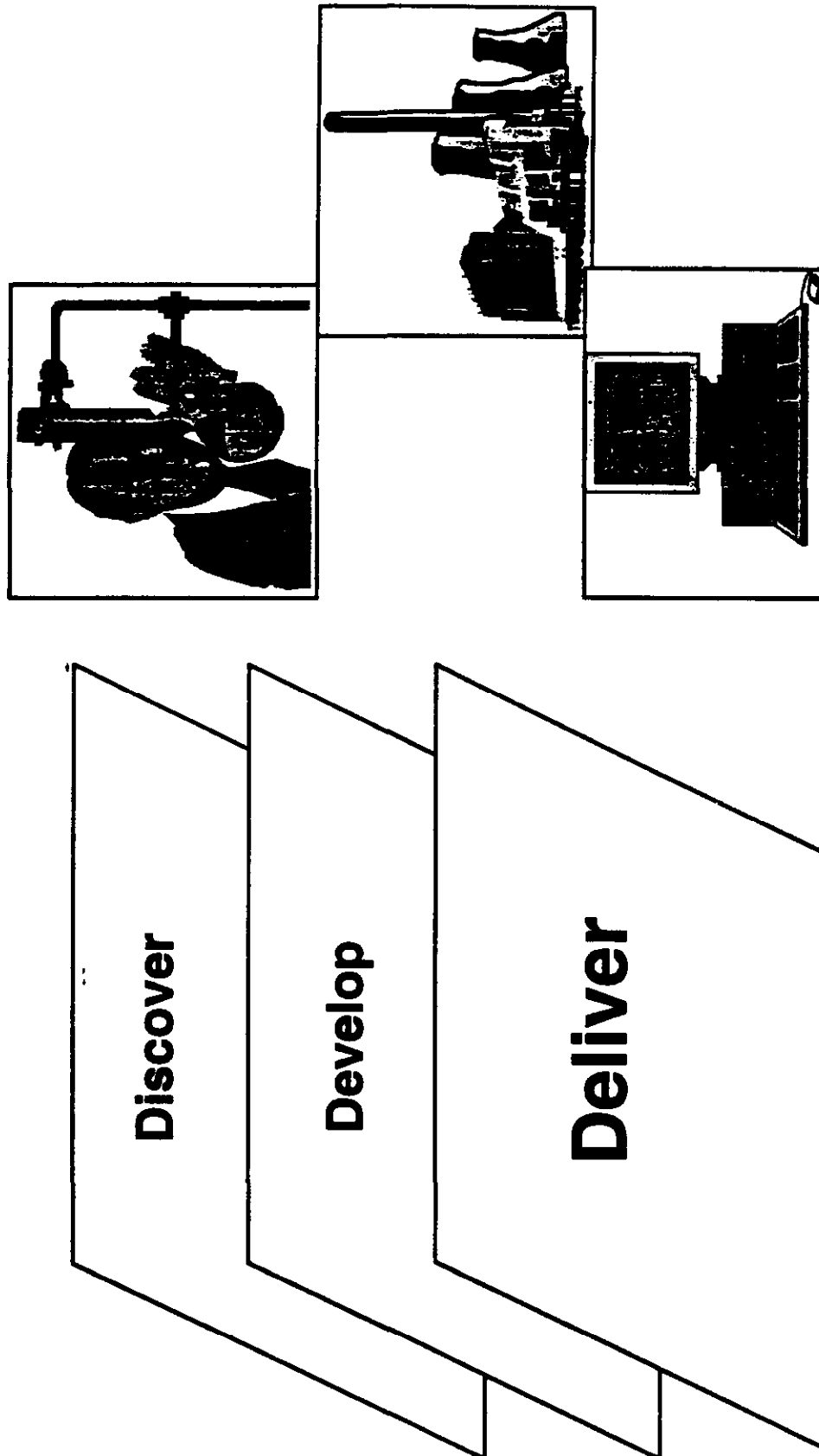
LOANED EMPLOYEES

Our policy has been to encourage loaned employees from members and affiliates as a direct means to encourage technology transfer. This has proved very valuable for both EPRI, which gains manpower and a direct input from the utility, and to the member, who gains direct experience in relevant research and development. The typical term is 1-2 years, with some terms shorter than this in order to accommodate special needs. The benefit to the loaned employee is that assignments offer rapid introduction to specific technologies, as well as the opportunity to establish close technology transfer links to EPRI staff, contractors, and technology suppliers.

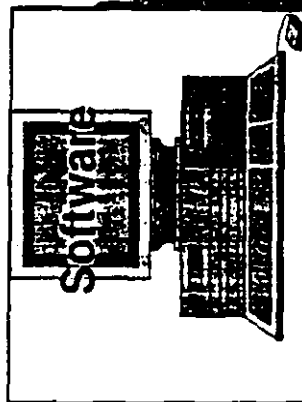
CONCLUSIONS

EPRI recognizes that the job is not complete until the technology is used and useful to the customer. We are adding many vehicles to deliver the information and spending more of our time and resources to complete this task. As we move to a more sophisticated technology, the tools to do this are also getting more sophisticated. We believe our outreach program gives us a good connection with our members, and a good foundation for the future, as we reach out towards new customers for our information at home and overseas.

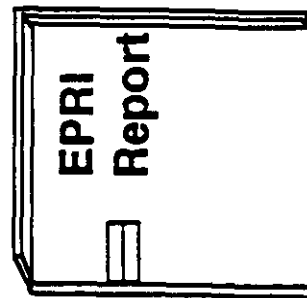
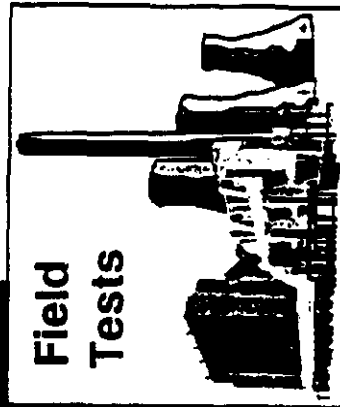
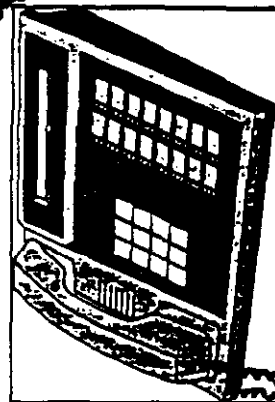
EPRI's Mission



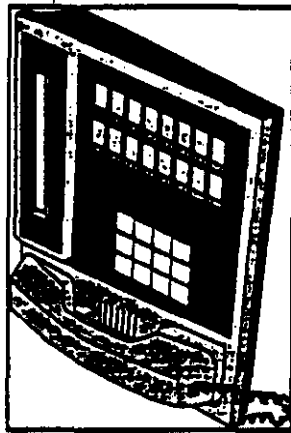
EPRI TECHNOLOGY TRANSFER



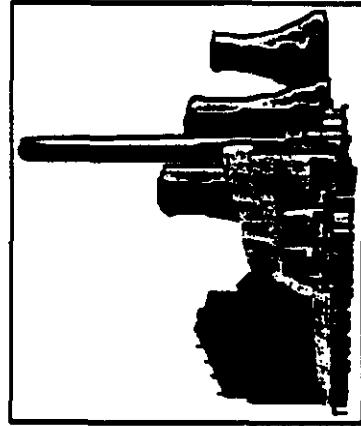
Assistance
Centers



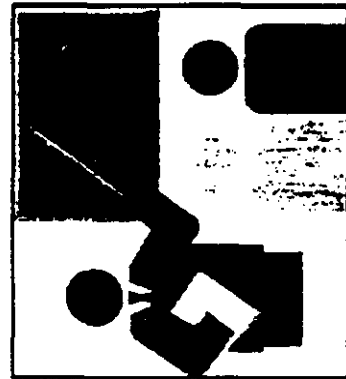
EPRI



**Technical Information
Telephone Assistance**



Jump Starts



Training & Seminars



**REMARKS BY BEN YAMAGATA
EXECUTIVE DIRECTOR OF THE CLEAN COAL TECHNOLOGY COALITION
SECOND ANNUAL DOE CLEAN COAL TECHNOLOGY CONFERENCE
SEPTEMBER 9, 1993**

We have asked the American taxpayer to provide more than \$2.7 billion to the clean coal technology demonstration program. Industry is likely to provide well over \$4.0 billion. What do we get from this expenditure of public and private funds? Hopefully, we get more, **much more**, than simply several scores of "successfully demonstrated" technologies.

Yesterday, Secretary White challenged this audience to step ahead of the trend; to take risks and to deploy these "successfully demonstrated" technologies. Otherwise, as the Secretary noted and as we know, the technologies will be "shelved" and not widely used. Well, how do we best insure deployment? What are those "deployment" considerations and, more importantly, what are the impediments to deployment?

The policy wonks, the political pundits, and the various custodians of the federal purse have argued, and will argue, that the role of government stops when the technology is "demonstrated." And, at that point in the process, it is argued, the government will step aside to let the marketplace work. Well, I'm not certain that will happen; in the case of successfully demonstrated technologies. Part of this Administration's "reinventing government" should include a recognition that the clean coal partnership between government and industry that got us here -- that is producing successfully demonstrated technologies -- ought to be continued until such time as the market might truly make its assessment about the technical **and economic** merit of these technologies.

Let's do some policy working of our own. What about adopting this policy: The role of government appropriately stops when the expenditure of public funds starts to provide a return to the taxpayer and/or when the marketplace evidences a willingness and an ability -- in the case of successfully demonstrated technologies -- to pursue the technologies into commercialization without further government involvement. This does not mean that government should simply pump additional funds into a technology's development. It does mean that government should carefully examine the remaining impediments to a technology's widespread use and, where appropriate, provide such further incentives to industry to enable the best assessment of whether or not the technically better technology, e.g. the one for superior in environmental performance and energy conversion, should be adopted. Clearly, if government stops at the demonstration phase and the technology is shelved, the taxpayer gets no return on the investment. Risk-taking certainly exists beyond the demonstration phase, the question to be asked is whether industry is willing, or able, to take those risks alone, or alternatively, whether government should be asked to further partner in the risk-taking in order to make the technology a real option for the market place.

I would like to focus my comments on "deployment considerations" by asserting that in the case of commercializing clean coal technologies government's involvement should not stop at the demonstration gate.

I'll discuss two areas in this regard: first, the need -- now -- for the domestic DOE CCT Program to focus on the domestic deployment of demonstrated technologies, and second, the need to recognize that to participate in the phenomenal growth of international power markets through use of clean coal or advanced coal technologies an

aggressive partnering between our government and industry to demonstrate technologies abroad will be required.

The Clean Coal Technology Coalition's (CCTC) primary mission has been to promote the development and use of CCTs. We are strong advocates for the DOE CCT Program and applaud the Department's and industry's success at developing many coal-based technologies. By current design, the DOE program is said to go no further than the initial demonstration of a technology. Since our inception in 1986, the Coalition has advocated the need to pursue a partnership with government in which more than one demonstration of the same or similar technology is supported by the clean coal program. Only in this way can we assure widespread acceptance of any given technology. There exists a gap (call it a "risk gap") between CCTs that have been successfully demonstrated (and presumably available for commercial use) and their widespread commercial use. We have developed a technology matrix in which we try to picture the developmental status of a variety of clean coal technologies. We'll be happy to provide that information to you.

While still too early to pass judgment, it appears that while success is being achieved in demonstrating advanced coal technologies, the market place -- for several reasons -- is not, indeed may have no plans, to adopt these technologies.

As many of you know, the United States Congress has directed the Department of Energy to examine and report by May of 1994 upon the need to conduct another solicitation of the clean coal program. Also, anticipating that a great deal of funds for previously selected projects might become available, the Congress expects the Department to provide suggestions regarding the use of those funds. I suspect that I do

not need to tell you that the budget knives are sharp and cutting, nor do I need to report that many other groups are gathering, watching and waiting to make their case for using those funds for other purposes. It is in this climate that the Coalition, in March of this year, created an advisory group from its membership to formulate a Coalition position on the advisability of pursuing a Round VI and to seek industry recommendations of the best use of any unobligated funds that might remain from the previous five rounds of selections.

After considering several options for the program, it became rapidly apparent that our recommendation would be to focus on the goal of deployment; that step before widespread use -- government to partner with industry to fill the gap I spoke of earlier.

The Coalition's advisory group completed its recommendation to the Coalition at the end of August. Currently, our full membership, as well as the Coalition's Executive Committee, are reviewing this proposal and we will have a set of recommendations to be made to the DOE by the end of this month. I would like to use this opportunity to talk about the Coalition's recommendation as it very specifically relates to our members' views regarding a means by which we might insure successful deployment of demonstrated clean coal technologies.

The first task undertaken by the advisory group was to determine what might hinder CCTs from enjoying widespread acceptance in the commercial sector. Clearly, some technologies are not yet ready for large-scale commercial application. However, for those that are, the question is why aren't power producers opting to use these technologies. The higher first-of-a-kind costs of these technologies, coupled with the significant risk that is associated with the use of any new technology, presents the most

significant impediment to deployment of CCTs. Utilities, a large segment of the potential power producing sector, are faced with a heavily-regulated environment which prevents them from accepting the level of risk and higher costs associated with initial introduction of a commercial CCT unit, especially in light of non-utility generators who are poised to provide new capacity based on mature, low cost natural gas or pulverized coal-fired operation. This problem is exacerbated by the limited capacity additions currently being undertaken by least-cost planning requirements, and by those Clean Air Act provisions which encourage decisions not predicated upon the use of new technology application.

One approach to this problem is to change the existing regulatory environment for power producers to encourage, rather than prohibit, the assumption of increased risk and cost of CCTs which are environmentally preferable to conventional technologies, and in many cases more efficient. David South, in his presentation today, will discuss changes to the regulatory structure and therefore I will not focus on this area. Further, the advisory group chose not to address regulatory reform in its recommendation to the Coalition due to the significant time delay and difficulties associated with the process of getting each state commission to change existing regulations. The Coalition, however, is supportive of regulatory reform and is seeking to lend its support to viable reform efforts.

What beyond regulatory reform may be viable?

The Coalition supports the concept of an enhanced CCT Program with the objective of moving previously demonstrated CCTs into widespread commercial use by reducing the financial risk assumed by those who opt to use CCTs which are not yet in

general commercial use. This enhanced program would continue to be industry cost-shared, with industry assuming an even greater financial exposure as these technologies move close to commercialization. Federal funding would provide a minimum cost-share and would come from the unobligated funds from Rounds 1-5 of the CCT Program.

The enhanced CCT Program would be market driven, allowing the consumer (industry) to select the technologies that would be pursued under the program. This would help ensure that only those technologies which have a reasonable chance for market penetration would continue to receive federal support. The Coalition is not advocating a "cookie cutter" demonstration program which encourages repeated iterations of a specific technology. Rather, what we are aiming at is to commercially demonstrate those technologies that display some form of innovation or evolution from a past demonstration.

The enhanced (deployment driven) CCT Program, as we envision it, would only address the incremental cost associated with CCTs relative to conventional coal processes. By using a formula to calculate the cost differential between a traditional coal combustion power generation plant and a CCT plant, taking into account such variables as capacity factor heat rate and some O&M costs, the DOE could reasonably estimate the financial support necessary to make a power producer "neutral" to selecting the clean coal technology over a conventional nature technology.

This kind of mechanism provides a built in protection system. As only those technologies which are cost competitive as measured on a levelized kwh basis will be selected for deployment efforts, any bidder with too high a proposal cost would not likely be selected for the program. Likewise, bidders anxious to participate in the program

who underestimate costs would receive only the predetermined increment -- therefore having to make up the difference themselves.

The CCTC strongly recommends that the DOE CCT Program needs to now be focused on deployment. At the same time, we also strongly support research and development of CCTs at the DOE, which we proposed to be carried out through the general Fossil Energy Budget. However, because the current CCT program is the only national program that supports major industry development of clean coal technologies, continuing this work in some way through the clean coal program is critical to improvements to CCTs. In other words, the recommendation the Coalition hopes to make would envelop and accommodate technology enhancements to existing demonstrations. Put another way, any R&D not directly associated with enhancing deployment of previously demonstrated technologies, either inside or outside the current CCT program would be outside the scope of the enhanced program I have outlined.

While modifying the DOE CCT Program has been the focus of the CCTC advisory group, Coalition members are aware that the large markets for CCTs are not at home, but in the international market. For this reason, the Coalition has strongly supported congressional appropriations to implement The Innovative Clean Coal Technology Transfer Program (Section 1332 Energy Policy Act). Ted Atwood will be speaking later about the DOE's strategy for implementing this program, but I think it is important to note that this program has the potential to be a link between the domestic CCT Program, and deployment of U.S. technologies in new markets in developing nations and countries with economies in transition. By placing U.S. technologies in other

nations, in showcase demonstrations, you are taking an important step toward reducing the perceived risk of these technologies.

Let me spend a moment re-reviewing these overseas markets.

Worldwide demand for power is expected to expand at rapid rates through the year 2010 so that, by the end of the next decade, world consumption of energy is projected to grow by almost 40%. Not surprisingly, energy consumption will grow most rapidly in the developing countries, possibly twice as fast as the developed countries.

As the worldwide demand for power expands, the international demand for coal and coal combustion technologies is also expected to grow at a rapid rate. According to the world bank, approximately 45% of the additional power supplied to less developed nations between 1990 and 2000 is expected to be generated by coal. China, the country with the highest expected growth in power generating capacity, will rely primarily upon coal. China has proven reserves of more than 950 billion tons and estimated reserves of 4 trillion tons. If these estimates prove correct, that's enough coal to last for several hundred years. India, expected to have the second largest new power generation needs in the world, will also rely heavily upon coal use - currently, India has approximately 68 million tons of recoverable coal reserves. Many countries around the world with domestic coal resources are planning to increase the use of their reserves to satisfy growing energy needs. Coal provides an abundant, secure and economic resource for these countries and increased coal consumption, along with growing environmental pressures world wide, will work together to increase demand for cct's throughout the world.

According to the Department of Energy, the potential cct market for new facilities, retrofit installations and follow-on work outside of the U.S. from 1992-2010 is projected to be between \$270 billion and \$750 billion. This represents a potential \$23.4 billion per year market. Thanks in large part to the DOE clean coal demonstration program, the U.S. has a strong and internationally competitive cct industry and is well positioned to participate in the growing worldwide markets. If U.S. suppliers are able to capture a significant market share for cct's, a great opportunity exists for our country to reduce our balance of trade and create high-value domestic jobs while furthering our *national commitment to the protection of the world environment*. There are also benefits to coal-consuming countries using clean coal technologies, including increasing their economic efficiency, mitigating environmental impacts and greater energy security as worldwide resources of coal exceed those of oil and gas and, unlike those of oil, are not geographically concentrated.

As Deputy Secretary White noted yesterday, the risk of damage to the environment will increase as a result of rapidly growing energy consumption in developing countries. The good news is that as these countries industrialize and increase their dependence on fossil fuels, the need will emerge to reduce environmental impacts of energy production, generation, and use by deploying the best available technology. The challenge, however, will be to encourage developing countries to implement "cleaner" advanced technologies at a time when most host country governments are most concerned with providing cheap, abundant electricity and have little regard for emission control. How can we skip a generation of technologies and enable adoption and use of the most modern technologies?

More narrowly defined, this challenge for the u.S. Focuses on 2 critical issues to ensure that a "foothold" is created in this enormous market for u.S. Companies. 1) How does the u.S. Demonstrate to developing countries that u.S. Suppliers offer some of the most advanced and efficient clean coal technologies available in the world today, thereby encouraging these countries to seek out business with u.S. Manufacturers? And 2) how do we as a nation, both the government and the private sector, help developing countries to finance the incremental cost of deploying advanced technologies such as cct's, thereby giving these less developed countries with serious capital constraints the incentive, and means, to implement cct's?

In order to meet this important challenge, I believe, that a stronger partnership must be forged between industry and government to facilitate the export of u.S. Cct's. Establishment of such a cooperative relationship would allow U.S. Cct manufacturers to effectively utilize federal export promotion programs in order to meet the financing needs required by advanced technology systems even before we can think about these technologies being widely used abroad. I believe that industry and government should share the burden of demonstrating first generation technologies in developing countries, giving these countries the opportunity to significantly increase their level of understanding and trust in the viability of better, but more expensive technology. At a minimum this means that government and industry ought to pursue demonstrations thru the implementation of section 1332 - which Ted Atwood will speak to shortly.

**BRIDGING THE GAP BETWEEN
CCT DEMONSTRATION AND
COMMERCIALIZATION: THE USE OF
REGULATORY INCENTIVES**

**David W. South
Economist/Program Manager
Argonne National Laboratory**

**(The comments of Mr. South were not
available at the time of publication.)**

IMPLEMENTING SECTION 1332, ENERGY POLICY ACT OF 1992

**Ted Atwood
Office of Clean Coal Technology/
U.S. Department of Energy**

DRAFT (8/31/93)
APPROACH FOR FOSSIL ENERGY
TECHNOLOGY TRANSFER PROGRAMS

BACKGROUND

Sections 1332 Clean Coal Technology, and 1608 Environmental Technology of the Energy Policy Act of 1992 (EPACT) describe two technology Transfer Programs for creating jobs and reducing the trade deficit for the United States, through providing financial assistance for projects to improve energy efficiency and reduce environmental emissions including "Greenhouse Gases." These projects are to be located in countries which are supported by the Agency for International Development (AID) or in countries with an economy in transition from a non-market to a market economy. The legislation requires a very similar approach for the two programs. Working with AID the DOE is to: 1) complete in 150 days an agreement with the appropriate US agencies for conducting the program in the host countries; 2) issue in 240 days a list of potential projects; 3) within one year issue a solicitation and 4) within 120 days after receipt of proposals make selection. In addition, the programs are to develop a procedure for providing financial assistance to projects applying for solicitations in other countries.

After an initial consultation with U.S. Treasury, Export-Import Bank, Overseas Private Investment Corp.(OPIC), and AID concerning Organization for Economic Cooperative Development rules for export credits, and the most appropriate means of financing projects under the Transfer Programs, it became apparent that, in addition to providing financing for projects through DOE programs, a more efficient, economical and prudent approach to implementing a transfer program would involve the financing of projects through organizations already experienced in the development of overseas investments. In order to accomplish this, the following program approach, should be considered.

PROPOSED APPROACH

Implementation of the Transfer Program created by EPACT would consist of a twofold approach to serve two different objectives.

"Showcase" Demonstrations

One objective would be to demonstrate a few advanced "showcase" technologies in key market areas. This would involve demonstrations of advanced technologies (for the purpose of this program advanced technologies are defined as having been demonstrated in the U.S., but have not achieved commercial replication in the U.S.) that both the U.S. Government, U.S. industry and the host countries industrial sector believe to have considerable future replication potential. However due to some of the first-of-a-kind aspects of utilizing the advance technology in the host country and the associated performance risk, the commercial means of financing may not be readily available for these projects. By DOE having a program to provide financial assistance up to 50% (the cost share could

be structured to achieve an acceptable rate of return) of the projected eligible capital and operating costs through cooperative agreements with repayment provisions, the selected "showcase" technologies could be demonstrated for evaluation by potential foreign and U.S. users. The features of this approach for marketing advanced technologies to developing countries includes providing a source of financing not obtainable through the commercial markets, distribution of risk among multiple funding sources, expediting the demonstration through a program involving a single government agency, developing a foundation overseas for market acceptance of future U.S. technologies through participation in the demonstration, and generating goodwill through investing in the development of technologies to satisfy the future needs of the host country. In order to increase U.S. sales abroad, more is involved than just offering the better "mouse trap" and project financing. It is important to demonstrate a willingness to invest in the future of your customer.

Export of Commercial Technology

The second approach would be designed to achieve an objective of resolving near term energy and associated environmental problems in foreign countries through the use of U.S. technology. Through this program technology that is commercial in the U.S., but not in the host country, could become more readily available through DOE sponsoring project definition activities (these could include sufficient engineering and design to support an adequate cost estimate for financing, developing supply and sales agreements, defining risks and approaches to mitigate risks) sufficient to obtain financing through the Export-Import Bank, OPIC, World Bank or commercial sources of financing. This program would encourage the export of commercially available U.S. equipment for meeting the current and near term needs of the eligible nations (as defined in secs. 1332 and 1608) and by doing so help to reduce the U.S. trade deficit and create high skilled U.S. jobs.

The program could be implemented through designating funding to the Export-Import Bank specifically for the financing of projects using the eligible technologies defined by secs. 1332 and 1608. Funds could also be designated to OPIC for providing insurance to projects in the Technology Transfer Program. DOE would provide funds for conceptual designs and definition for projects utilizing eligible technologies. The DOE funds would be cost shared up to fifty percent with U.S. industry for investigating and defining projects in eligible countries. Where appropriate these studies could be conducted in conjunction with the Trade Development Agency (TDA) or AID. DOE could serve as the focal point and lead coordinator among the federal agencies to ensure a smooth transition from the definition phase to the ultimate financing organization. Prior to initiating a study it would be determined that the project represents a development priority for the host country, financing for the project is likely if the study results are attractive and the potential for U.S. exports for subsequent projects is significant. Based on the results of these studies the industrial participant could elect to seek financing from the funds "ear marked" at the other agencies or any other source. Projects with sufficient definition could proceed directly to the Export-Import Bank for financing. The DOE would provide the Export-Import Bank

with the technical experts for evaluating investments and would participate in the monitoring of the technical progress during project implementation.

A small fund could also be earmarked at TDA for feasibility studies for the eligible technologies and for training of host country technical, government and business personnel. TDA provides grants to the host country for conducting very preliminary low cost feasibility studies to determine if the idea merits future investment. These studies may not provide sufficient definition for financing or project control. The definition activities that would be cost shared by DOE would provide this information and would be more costly than the feasibility study, therefore requiring cost sharing to demonstrate commitment by the U.S. firm and host country. Investment in front end definition for projects repeatedly pays off in the long term through reduced technical and business uncertainty resulting in less potential for cost overruns.

There are considerable advantages to structuring the program to use the existing expertise of organizations well versed in overseas financing and the OECD regulations. The DOE does not have the expertise required for international finance nor does the DOE procurement system easily accommodate the issuing of loans and loan guarantees. Financing done through DOE would be very limited in the ability to leverage the government funds and DOE would not have the financing flexibility of the other agencies. Traditionally the Export-Import Bank funds are leveraged twenty-to-one, thus a \$600 million fund at the bank could finance over \$12 billion of projects when considering the equity invested. Using the Bank and OPIC for financing will provide greater flexibility through having more mechanisms of financing available. The World Bank Global Environmental Fund could also be a source of financing for the projects.

In the international market the financing flexibility and terms maybe more important for equipment sales and services than the merits of the technology being offered. To achieve the objectives of the Technology Transfer Program defined by the Energy Policy Act, there is considerable merit to implementing the program through a marriage of the DOE technical expertise and the financial and business expertise of the agencies created for assisting overseas projects. By structuring the program as described, industry would continue to work with the same organizations as it has in the past for seeking overseas financing.

Applicable Projects and Technologies

Both approaches would be applicable to projects in the host countries where the U.S. firm has an equity interest in the project, this could include grassroots, retrofit or repowering projects. Where appropriate government financing could be packaged for the entire project, for the incremental cost for the portion of the project applicable to energy efficiency or environmental controls, or just for the differential cost of using U.S. technology rather than the conventional technology generic to the host country.

Under sec 1332 the project should use U.S. clean coal technology, and where appropriate U.S. coal resources, in meeting the applicable energy

and environmental requirements of the host country. Under sec. 1608 the project should use a U.S. technology that substantially reduces environmental pollutants, including greenhouse gases, in meeting the applicable energy and environmental requirements of the host country.

Solicitation Structure

There are three basic ways to structure the solicitations for projects under the program 1) one step process, 2) two step process or 3) a program rule. The one step process is exactly the same as the solicitations for the clean coal program. A proposal is submitted and by a certain date selections are made. Usually this approach does not allow for discussions between the proposer and the government prior to selection.

The two step selection process would reduce the proposals to a competitive range and discussions would be conducted with these proposers. This should result in a better selection through gaining a more accurate understanding of the validity of the information contained in the proposals. The winning proposals would be selected from those in the competitive range. By narrowing the field of selection prior to discussions, the two step process would not be significantly longer than the single step process.

If the solicitation were for the showcase demonstrations a variation of the two step process could be used. Proposals could be selected for definition activities followed by a second selection prior to detailed design and construction. This would allow the selection of more projects for definition then there is funding for construction. Since these are demonstrations, there is uncertainty as to the continued viability or attractiveness of the project as the definition activities proceed. By over selecting and having a second screening prior to funding detailed design and construction there is a higher probability of successful demonstrations resulting in future sales of equipment and services.

The third method is called a program rule, this is an open ended solicitation. Over a period of time proposals are submitted and reviewed based upon in the priority of when received. The open period for submittal could be up to two years. The program rule has not been widely used in the Department. Another difficulty, especially in a political environment, is the pacing of the selections to prevent the entire funding from being awarded to just early submittals.

Staged Solicitations

Considering the experience gained under the Clean Coal Program it might be appropriate to have multiple sequential solicitations. The subsequent solicitations in the Clean Coal Program profited from the learning experience of the prior solicitations resulting in considerable improvements in each round. A prudent approach to successfully implementing the program is to limit the initial solicitation to a few key countries with attractive markets for U.S. technology, that have a practical approach to a free market economy as well as an attractive business climate and acceptable political risks.

After gaining the experience of the first solicitation then issue subsequent solicitations encompassing more countries or dedicated to different countries. Initially the solicitation maybe targeted to projects located in one or two countries in eastern Europe and Asia.

Limited Funding

If the funding is significantly less than authorized (\$1.2 billion) by 1332 and 1608 (less than \$100 million) the most useful program approach maybe to limit the government funds to project definition activities or financing the differential cost of using U.S. technology, or incremental cost of pollution control for smaller projects. The funding of definition activities would reduce the front end costs of project development for industry while enabling activities to proceed that are necessary to obtain the financing of the project through other government programs, World Bank or commercial institutions. The DOE could assist in coordinating with the ultimate project funding agency to ensure the most appropriate actives are being pursued during the definition phase.

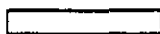
Schedule

A schedule of activities for the development and issuing of a solicitation by early Fy 1995 is attached.

Schedule for Innovative Technology

Transfer Program (EPAct secs. 1211, 1332, & 1608)

Activity	FY93					FY94										FY95				
	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	
MOU with AID	(Awaiting S-1 Approval)																			
Interagency Agreement AID																				
Develop working relationship with TDA, EXIM BANK & OPIC																				
Define Eligible Technology for 1608 & Issue list																				
Define EE/FE roles for 1608																				
Target Markets/Project Lists																				
Market Analysis																				
Selection Criteria																				
Develop Project List Mechanism																				
Develop Project List																				
Financing Mechanism																				
Survey Industry/Trade Groups																				
Survey other Agencies																				
Consult CORECT, COEECT, & CCT Subgroup																				
Develop Mechanism with AID																				
Public Meeting (Optional)																				
Solicitation																				
Evaluate Options																				
Determine NEPA Applicability & Incorporate into Solicitation																				
Develop Solicitation with AID, EXIM Bank																				
Issue Draft for Public Review																				
Public Meeting (Optional)																				
Issue Solicitation																				
EE/FE Report to Congress																				



Denotes Statutory deadline

coal technology transfer program to carry out the purposes described in subsection (b). Within 150 days after the date of enactment of this Act, the Secretary and the Administrator of the Agency for International Development shall enter into a written agreement to carry out this section. The agreement shall establish a procedure for resolving any disputes between the Secretary and the Administrator regarding the implementation of specific projects. With respect to countries not assisted by the Agency for International Development, the Secretary may enter into agreements with other appropriate United States agencies. If the Secretary and the Administrator, or the Secretary and an agency described in the previous sentence, are unable to reach an agreement, each shall send a memorandum to the President outlining an appropriate agreement. Within 90 days after receipt of either memorandum, the President shall determine which version of the agreement shall be in effect. Any agreement entered into under this subsection shall be provided to the appropriate committees of the Congress and made available to the public.

(b) **PURPOSES OF THE PROGRAM.**—The purposes of the technology transfer program under this section are to—

- (1) reduce the United States balance of trade deficit through the export of United States energy technologies and technological expertise;
- (2) retain and create manufacturing and related service jobs in the United States;
- (3) encourage the export of United States technologies, including services related thereto, to those countries that have a need for developmentally sound facilities to provide energy derived from coal resources;
- (4) develop markets for United States technologies and where appropriate, United States coal resources to be utilized in meeting the energy and environmental requirements of foreign countries;
- (5) better ensure that United States participation in energy-related projects in foreign countries includes participation by United States firms as well as utilization of United States technologies that have been developed or demonstrated in the United States through publicly or privately funded demonstration programs;
- (6) provide for the accelerated deployment of United States technologies that will serve to introduce into foreign countries United States technologies intended to use coal resources in a more efficient, cost-effective, and environmentally acceptable manner;
- (7) serve to ensure the introduction of United States firms and expertise in foreign countries;
- (8) provide financial assistance by the Federal Government to foster greater participation by United States firms in the financing, ownership, design, construction, or operation of clean coal technology projects in foreign countries;
- (9) assist foreign countries in meeting their energy needs through the use of coal in an environmentally acceptable manner, consistent with sustainable development policies; and
- (10) assist United States firms, especially firms that are in competition with firms in foreign countries, to obtain opportunities to transfer technologies to, or undertake projects in, foreign countries.

SEC. 1333. INNOVATIVE CLEAN COAL TECHNOLOGY TRANSFER PROGRAM. 42 USC 13362

GRAM.

(a) **ESTABLISHMENT OF PROGRAM.**—The Secretary, through the Agency for International Development, and in consultation with the other members of the CCT Subgroup, shall establish a clean

(c) IDENTIFICATION.—Pursuant to the agreements required by subsection (a), the Secretary, through the Agency for International Development, and after consultation with the CCT Subgroup, United States firms, and representatives from foreign countries, shall develop mechanisms to identify potential energy projects in host countries, and shall identify a list of such projects within 240 days after the date of enactment of this Act, and periodically thereafter.

(d) FINANCIAL MECHANISMS.—(1) Pursuant to the agreements under subsection (a), the Secretary, through the Agency for International Development, shall—

(A) establish appropriate financial mechanisms to increase the participation of United States firms in energy projects utilizing United States clean coal technologies, and services related thereto, in developing countries and countries making the transition from nonmarket to market economies;

(B) utilize available financial assistance authorized by this section to counterbalance assistance provided by foreign governments to non-United States firms; and

(C) provide financial assistance to support projects, including—

(i) financing the incremental costs of a clean coal technology project attributable only to expenditures to prevent or abate emissions;

(ii) providing the difference between the costs of a conventional energy project in the host country and a comparable project that would utilize a clean coal technology capable of achieving greater efficiency of energy products and improved environmental emissions compared to such conventional project; and

(iii) such other forms of financial assistance as the Secretary, through the Agency for International Development, considers appropriate.

(2) The financial assistance authorized by this section may be—

(A) provided in combination with other forms of financial assistance, including non-United States funding that is available to the project; and

(B) utilized to assist United States firms to develop innovative financing packages for clean coal technology projects that seek to utilize other financial assistance programs available through other Federal agencies.

(3) United States obligations under the Arrangement on Guidelines for Officially Supported Export Credits established through the Organization for Economic Cooperation and Development shall be applicable to this section.

(e) SOLICITATIONS FOR PROJECT PROPOSALS.—(1) Pursuant to the agreements under subsection (a), the Secretary, through the Agency for International Development, within one year after the date of enactment of this Act, and subsequently as appropriate thereafter, shall solicit proposals from United States firms for the design, construction, testing, and operation of the project or projects identified under subsection (c) which propose to utilize a United States technology. Each solicitation under this section shall establish a closing date for receipt of proposals.

(2) The solicitation under this subsection shall, to the extent appropriate, be modeled after the RFP No. DE-PS01-90FEG271

Clean Coal Technology IV as administered by the Department of Energy.

(3) Any solicitation made under this subsection shall include the following requirements:

(A) The United States firm that submits a proposal in response to the solicitation shall have an equity interest in the proposed project.

(B) The project shall utilize a United States clean coal technology, including services related thereto, and, where appropriate, United States coal resources, in meeting the applicable energy and environmental requirements of the host country.

(C) Proposals for projects shall be submitted by and undertaken with a United States firm, although a joint venture or other teaming arrangement with a non-United States manufacturer or other non-United States entity is permissible.

(f) ASSISTANCE TO UNITED STATES FIRMS.—Pursuant to the agreements under subsection (a), the Secretary, through the Agency for International Development, and in consultation with the CCT Subgroup, shall establish a procedure to provide financial assistance to United States firms under this section for a project identified under subsection (c) where solicitations for the project are being conducted by the host country or by a multilateral lending institution.

(g) OTHER PROGRAM REQUIREMENTS.—Pursuant to the agreements under subsection (a), the Secretary, through the Agency for International Development, and in consultation with the CCT Subgroup, shall—

(1) establish eligibility criteria for countries that will host projects;

(2) periodically review the energy needs of such countries and export opportunities for United States firms for the development of projects in such countries;

(3) consult with government officials in host countries and, as appropriate, with representatives of utilities or other entities in host countries, to determine interest in and support for potential projects; and

(4) determine whether each project selected under this section is developmentally sound, as determined under the criteria developed by the Development Assistance Committee of the Organization for Economic Cooperation and Development.

(h) SELECTION OF PROJECTS.—(1) Pursuant to the agreements under subsection (a), the Secretary, through the Agency for International Development, shall, not later than 120 days after receipt of proposals in response to a solicitation under subsection (e), select one or more proposals under this section.

(2) In selecting a proposal under this section, the Secretary, through the Agency for International Development, shall consider—

(A) the ability of the United States firm, in cooperation with the host country, to undertake and complete the project;

(B) the degree to which the equipment to be included in the project is designed and manufactured in the United States;

(C) the long-term technical and competitive viability of the United States technology, and services related thereto, and the ability of the United States firm to compete in the develop-

national Development pursuant to applicable law or regulation; or

(B) a developing country or country with an economy in transition from a nonmarket to a market economy.

(m) AUTHORIZATION FOR PROGRAM.—There are authorized to be appropriated to the Secretary to carry out the program required by this section, \$100,000,000 for each of the fiscal years 1993, 1994, 1995, 1996, 1997, and 1998.

ment of additional energy projects using such technology in the host country and in other foreign countries;

(D) the extent of technical and financial involvement of the host country in the project;

(E) the extent to which the proposed project meets the goals and objectives stated in section 1301(a);

(F) the extent of technical, financial, management, and marketing capabilities of the participants in the project, and the commitment of the participants to completion of a successful project in a manner that will facilitate acceptance of the United States technology for future application; and

(G) such other criteria as may be appropriate.

(3) In selecting among proposed projects, the Secretary shall seek to ensure that, relative to otherwise comparable projects in the host country, a selected project will meet 1 or more of the following criteria:

(A) It will reduce environmental emissions to an extent greater than required by applicable provisions of law.

(B) It will increase the overall efficiency of the utilization of coal, including energy conversion efficiency and, where applicable, production of products derived from coal.

(C) It will be a more cost-effective technological alternative, based on life cycle capital and operating costs per unit of energy produced and, where applicable, costs per unit of product produced.

Priority in selection shall be given to those projects which, in the judgment of the Secretary, best meet one or more of these criteria.

(I) UNITED STATES-ASIA ENVIRONMENTAL PARTNERSHIP.—Activities carried out under this section shall be coordinated with the United States-Asia Environmental Partnership.

(J) BUY AMERICA.—In carrying out this section, the Secretary, through the Agency for International Development, and pursuant to the agreements under subsection (a), shall ensure—

(1) the maximum percentage, but in no case less than 50 percent, of the cost of any equipment furnished in connection with a project authorized under this section shall be attributable to the manufactured United States components of such equipment; and

(2) the maximum participation of United States firms.

In determining whether the cost of United States components equals or exceeds 50 percent, the cost of assembly of such United States components in the host country shall not be considered a part of the cost of such United States component.

(K) REPORTS TO CONGRESS.—The Secretary and the Administrator of the Agency for International Development shall report annually to the Committee on Energy and Natural Resources of the Senate and the appropriate committees of the House of Representatives on the progress being made to introduce clean coal technologies into foreign countries.

(I) DEFINITION.—For purposes of this section, the term "host country" means a foreign country which is—

(1) the participant in or the site of the proposed clean coal technology project; and

(2) either—

(A) classified as a country eligible to participate in development assistance programs of the Agency for Inter-

SEC. 1608. INNOVATIVE ENVIRONMENTAL TECHNOLOGY TRANSFER PROGRAM.

(a) ESTABLISHMENT OF PROGRAM.—The Secretary, through the Agency for International Development, and in consultation with the interagency working group established under section 256(d) of the Energy Policy and Conservation Act (in this section referred to as the "interagency working group", shall establish a technology transfer program to carry out the purposes described in subsection (b). Within 150 days after the date of the enactment of this Act, the Secretary and the Administrator of the Agency for International Development shall enter into a written agreement to carry out this section. The agreement shall establish a procedure for resolving any disputes between the Secretary and the Administrator regarding the implementation of specific projects. With respect to countries not assisted by the Agency for International Development, the Secretary may enter into agreements with other appropriate Federal agencies. If the Secretary and the Administrator, or the Secretary and an agency described in the previous sentence, are unable to reach an agreement, each shall send a memorandum to the President outlining an appropriate agreement. Within 90 days after receipt of either memorandum, the President shall determine which version of the agreement shall be in effect. Any agreement entered into under this subsection shall be provided to the appropriate committees of the Congress and made available to the public.

(b) PURPOSES OF THE PROGRAM.—The purposes of the technology transfer program under this section are to—

- (1) reduce the United States balance of trade deficit through the export of United States energy technologies and technological expertise;
- (2) retain and create manufacturing and related service jobs in the United States;
- (3) encourage the export of United States technologies, including services related thereto, to those countries that have a need for developmentally sound facilities to provide energy derived from technologies that substantially reduce environmental pollutants, including greenhouse gases;
- (4) develop markets for United States technologies, including services related thereto, that substantially reduce environmental pollutants, including greenhouse gases, that meet the energy and environmental requirements of foreign countries;
- (5) better ensure that United States participation in energy-related projects in foreign countries includes participation by United States firms as well as utilization of United States technologies;
- (6) ensure the introduction of United States firms and expertise in foreign countries;
- (7) provide financial assistance by the Federal Government to foster greater participation by United States firms in the financing, ownership, design, construction, or operation of technologies or services that substantially reduce environmental pollutants, including greenhouse gases; and
- (8) assist United States firms, especially firms that are in competition with firms in foreign countries, to obtain opportunities

ties to transfer technologies to, or undertake projects in, foreign countries.

(c) IDENTIFICATION.—Pursuant to the agreements required by subsection (a), the Secretary, through the Agency for International Development, and after consultation with the interagency working group, United States firms, and representatives from foreign countries, shall develop mechanisms to identify potential energy projects in host countries that substantially reduce environmental pollutants, including greenhouse gases, and shall identify a list of such projects within 240 days after the date of the enactment of this Act, and periodically thereafter.

(d) FINANCIAL MECHANISMS.—(1) Pursuant to the agreements under subsection (a), the Secretary, through the Agency for International Development, shall—

(A) establish appropriate financial mechanisms to increase the participation of United States firms in energy projects, and services related thereto, that substantially reduce environmental pollutants, including greenhouse gases in foreign countries;

(B) utilize available financial assistance authorized by this section to counterbalance assistance provided by foreign governments to non-United States firms; and

(C) provide financial assistance to support projects.

(2) The financial assistance authorized by this section may be—

(A) provided in combination with other forms of financial assistance, including non-Federal funding that may be available for the project; and

(B) utilized in conjunction with financial assistance programs available through other Federal agencies.

(3) United States obligations under the Arrangement on Guidelines for Officially Supported Export Credits established through the Organization for Economic Cooperation and Development shall be applicable to this section.

(e) SOLICITATIONS FOR PROJECT PROPOSALS.—(1) Pursuant to the agreements under subsection (a), the Secretary, through the Agency for International Development, within one year after the date of the enactment of this Act, and subsequently as appropriate thereafter, shall solicit proposals from United States firms for the design, construction, testing, and operation of the project or projects identified under subsection (c) which propose to utilize a United States technology or service. Each solicitation under this section shall establish a closing date for receipt of proposals.

(2) The solicitation under this subsection shall, to the extent appropriate, be modeled after the RFP No. DE-PS01-90FE6271 Clean Coal Technology IV, as administered by the Department of Energy.

(3) Any solicitation made under this subsection shall include the following requirements:

(A) The United States firm that submits a proposal in response to the solicitation shall have an equity interest in the proposed project.

(B) The project shall utilize a United States technology, including services related thereto, that substantially reduce environmental pollutants, including greenhouse gases, in meeting the applicable energy and environmental requirements of the host country.

(C) Proposals for projects shall be submitted by and undertaken with a United States firm, although a joint venture or other teaming arrangement with a non-United States manufacturer or other non-United States entity is permissible.

(F) ASSISTANCE TO UNITED STATES FIRMS.—Pursuant to the agreements under subsection (a), the Secretary, through the Agency for International Development, and in consultation with the interagency working group, shall establish a procedure to provide financial assistance to United States firms under this section for a project identified under subsection (c) where solicitations for the project are being conducted by the host country or by a multilateral lending institution.

(G) OTHER PROGRAM REQUIREMENTS.—Pursuant to the agreements under subsection (a), the Secretary, through the Agency for International Development, and in consultation with the interagency working group, shall—

- (1) establish eligibility criteria for countries that will host projects;
- (2) periodically review the energy needs of such countries and export opportunities for United States firms for the development of projects in such countries;
- (3) consult with government officials in host countries and, as appropriate, with representatives of utilities or other entities in host countries, to determine interest in and support for potential projects; and

(4) determine whether each project selected under this section is developmentally sound, as determined under the criteria developed by the Development Assistance Committee of the Organization for Economic Cooperation and Development.

(H) ELIGIBLE TECHNOLOGIES.—Not later than 6 months after the date of the enactment of this Act, the Secretary shall prepare a list of eligible technologies and services under this section. In preparing such a list, the Secretary shall consider fuel cell powerplants, aeroderivative gas turbines and catalytic combustion technologies for aeroderivative gas turbines, ocean thermal energy conversion technology, anaerobic digester and storage tanks, and other renewable energy and energy efficiency technologies.

(I) SELECTION OF PROJECTS.—(1) Pursuant to the agreements under subsection (a), the Secretary, through the Agency for International Development, shall, not later than 120 days after receipt of proposals in response to a solicitation under subsection (e), select one or more proposals under this section.

(2) In selecting a proposal under this section, the Secretary, through the Agency for International Development, shall consider—

- (A) the ability of the United States firm, in cooperation with the host country, to undertake and complete the project;
- (B) the degree to which the equipment to be included in the project is designed and manufactured in the United States;

(C) the long-term technical and competitive viability of the United States technology, and services related thereto, and the ability of the United States firm to compete in the development of additional energy projects using such technology in the host country and in other foreign countries;

(D) the extent of technical and financial involvement of the host country in the project;

(E) the extent to which the proposed project meets the purposes of this section;

(F) the extent of technical, financial, management, and marketing capabilities of the participants in the project, and the commitment of the participants to completion of a successful project in a manner that will facilitate acceptance of the United States technology or service for future application; and

(G) such other criteria as may be appropriate.

(3) In selecting among proposed projects, the Secretary shall seek to ensure that, relative to otherwise comparable projects in the host country, a selected project will meet the following criteria:

(A) It will reduce environmental emissions, including greenhouse gases, to an extent greater than required by applicable provisions of law.

(B) It will be a more cost-effective technological alternative, based on life cycle capital and operating costs per unit of energy produced and, where applicable, costs per unit of product produced.

(C) It will increase the overall efficiency of energy use.

Priority in selection shall be given to those projects which, in the judgment of the Secretary, best meet these criteria.

(J) UNITED STATES-ASIA ENVIRONMENTAL PARTNERSHIP.—Activities carried out under this section shall be coordinated with the United States-Asia Environmental Partnership.

(K) BUY AMERICA.—In carrying out this section, the Secretary, through the Agency for International Development, and pursuant to the agreements under subsection (a), shall ensure—

- (1) the maximum percentage, but in no case less than 50 percent, of the cost of any equipment furnished in connection with a project authorized under this section shall be attributable to the manufactured United States components of such equipment; and

(2) the maximum participation of United States firms.

In determining whether the cost of United States components equals or exceeds 50 percent, the cost of assembly of such United States components in the host country shall not be considered a part of the cost of such United States component.

(L) REPORT TO CONGRESS.—The Secretary and the Administrator of the Agency for International Development shall report annually to the Committee on Energy and Natural Resources of the Senate and the appropriate committees of the House of Representatives on the progress being made to introduce innovative energy technologies, and services related thereto, that substantially reduce environmental pollutants, including greenhouse gases, into foreign countries.

(M) DEFINITIONS.—For purposes of this section—

(1) the term "host country" means a foreign country which is—

- (A) the participant in or the site of the proposed innovative energy technology project; and
- (B) either—

- (i) classified as a country eligible to participate in development assistance programs of the Agency for

International Development pursuant to applicable law or regulation; or

(ii) a developing country; and

(2) the term "developing country", includes, but is not limited to, countries in Central and Eastern Europe or in the independent states of the former Soviet Union.

(n) AUTHORIZATION FOR PROGRAM.—There are authorized to be appropriated to the Secretary to carry out the program required by this section, \$100,000,000 for each of the fiscal years 1993, 1994, 1995, 1996, 1997, and 1998.

International Forum

Delegate Introduction:

Ted Atwood,

Office of Clean Coal Technology/

U.S. Department of Energy

Robert Munn/Albert Doub,

United States Energy Association

Delegations from Eastern European countries, the Russian Federation and Asian countries were available for discussions regarding the strategic plans for coal and potential opportunities for coal and clean coal technologies in their respective countries.

Session 5

Coal Combustion/ Coal Processing

Co-Chairs:

Robert M. Kornosky,

Pittsburgh Energy Technology Center/

U.S. Department of Energy

Douglas M. Jewell,

Morgantown Energy Technology Center/

U.S. Department of Energy

**ROSEBUD SYNCOAL* PARTNERSHIP
ADVANCED COAL CONVERSION PROCESS
DEMONSTRATION PROJECT**

**R.W. Sheldon, P.E.
Western SynCoal Company
Billings, MT**

**Steven J. Heintz
U.S. Department of Energy
Pittsburgh Energy Technology Center
Pittsburgh, PA**

**ROSEBUD SYNCOAL PARTNERSHIP
ADVANCED COAL CONVERSION PROCESS
DEMONSTRATION PROJECT**

INTRODUCTION

Rosebud SynCoal® Partnership's Advanced Coal Conversion Process (ACCP) is an advanced thermal coal drying process coupled with physical cleaning techniques to upgrade high-moisture, low-rank coals to produce a high-quality, low-sulfur fuel.

The coal is processed through two vibrating fluidized bed reactors that remove chemically bound water, carboxyl groups, and volatile sulfur compounds. After drying, the coal is put through a deep-bed stratifier cleaning process to effect separation of the pyrite rich ash.

The process enhances low-rank western coals with moisture contents ranging from 25-55%, sulfur contents between 0.5 and 1.5%, and heating values between 5,500 and 9,000 Btu/lb. The upgraded stable coal product has moisture contents as low as 1%, sulfur contents as low as 0.3%, and heating values up to 12,000 Btu/lb.

Construction of the 300,000 ton per year (tpy) demonstration plant adjacent to Western Energy Company's Rosebud mine unit train loadout facility near the town of Colstrip in southeastern Montana was completed in 1992. Rosebud SynCoal's demonstration plant is sized at about one-tenth the projected throughput of a multiple processing train commercial facility.

Demonstration operations began in April 1992 and are continuing. Initial operations discovered the normal variety of equipment problems which delayed operational and process testing. As

operational testing has proceeded, the product quality issues that have emerged are dustiness and stability. The SynCoal® product has met the BTU, moisture and sulfur specifications. The project team is continuing process testing and is working toward resolution of the operational and process issues.

The ACCP Demonstration Facility is a U.S. Department of Energy (DOE) Clean Coal Technology Program Project with 50% funding from the DOE and 50% from the Rosebud SynCoal Partnership.

The Rosebud SynCoal Partnership is a venture involving Western SynCoal Company and Scoria Inc.. Western SynCoal is a subsidiary of Western Energy Company (WECO) which is a subsidiary of Entech Inc., Montana Power Company's non-utility group. Scoria Inc is a subsidiary of NRG Energy Inc., Northern States Power's non-utility group.

STATUS OF DEVELOPMENT

Much of the early ACCP development was performed using a small, 150 pound per hour pilot plant located at the Mineral Research Center, south of Butte, Montana. Up to 100 ton lots were produced to assess shipping and handling stability as well as chemical characteristics. A variety of coals and process conditions were tested to determine the process capabilities.

Development is continuing as construction and startup has been completed and demonstration operation is continuing at the 300,000 ton per year demonstration plant at Western Energy's Rosebud Mine near Colstrip, Montana. Many of the demonstration components are near commercial size. A larger commercial plant would use multiple modules.

PROCESS DESIGN DESCRIPTION

In general, the ACCP is a drying and conversion process using low pressure, superheated gases to process coal in vibrating fluidized beds. Two vibratory fluidized processing stages are used to heat and dry the coal followed by a water spray quench and a vibratory fluidized stage to cool

the coal. The solid impurities are then removed from the dried coal using pneumatic separators. Other systems servicing and assisting the coal conversion system are:

- Product Handling
- Raw Coal Handling
- Emission Control
- Heat Plant
- Heat Rejection
- Utility and Ancillary

The nominal throughput of the demonstration plant is 450,000 tpy (1,640 tpd) of raw coal, providing 270,000 tpy (988 tpd) of coarse coal product and 66,000 tpy (240 tpd) of coal fines (minus 20 mesh). The fines are to be collected and sold, giving a combined product rate of 335,000 tpy (1,228) tpd of high-quality, clean coal product. The central processes are depicted in Figure 1, the Process Flow Schematic.

Coal Conversion

The coal conversion is performed in two parallel processing trains. Each consists of two 5-feet wide by 30-feet long vibratory fluidized bed dryer/reactors in series, followed by a water spray quench section and a 5-feet wide by 25-feet long vibratory cooler. Each processing train is fed 1,139 pounds per minute of sized coal.

In the first-stage dryer/reactors, the coal is heated using recirculated combustion gases, removing primarily surface water from the coal. The coal exits the first-stage dryer/reactors, at a temperature slightly above that required to evaporate water, and is gravity fed into the second-stage dryer/reactors. Here the coal is heated further using a superheated gas stream, removing water trapped in the pore structure of the coal, and promoting decarboxylation. The superheated gases used in the second stage are actually produced from the coal. The make-gas from the second stage system is used as an additional fuel source in the process furnace, incinerating all

the hydrocarbon gases produced in the process. The particle shrinkage that liberates ash minerals and imparts a unique cleaning characteristic to the dried coal also occurs in the second stage. As the coal exits the second-stage dryer/reactors, it falls through vertical quench coolers where process water is sprayed onto the coal to reduce the temperature. The water vaporized during this operation is drawn back into the second-stage exhaust gas. After quenching, the coal enters the vibratory coolers where the coal is contacted by cool inert gas. The coal exits the cooler at less than 150 degrees Fahrenheit (F) and is conveyed to the coal cleaning system. The cooler exit gas is cooled by direct contact with water prior to returning to the vibratory fluidized coolers.

Coal Cleaning

The coal entering the cleaning system is screened into four size fractions: plus 1/2 inch, 1/2 by 1/4 inch, 1/4 inch by 6 mesh, and minus 6 mesh. These streams are fed in parallel to four deep-bed stratifiers (stoners), where a rough specific gravity separation is made using fluidizing air and a vibratory conveying action. The light (lower specific gravity) streams from the stoners are sent to the product conveyor; the heavy streams from all but the minus 6 mesh stream are sent to gravity separators. The heavy fraction of the minus 6 mesh stream goes directly to the waste conveyor. The gravity separators, again using air and vibration to effect a separation, each split the coal into light and heavy fractions. The light stream is considered product; the heavy or waste stream is sent to a 300 ton storage bin to await transport to an off site user or alternately back to a mined out pit disposal site. The dry, cool, and clean product from coal cleaning enters the product handling system.

Product Handling

Product handling conveys the clean product coal to two 6,000 ton capacity concrete silos and allows unit train loading with the mine's tippie loadout system.

Raw Coal Handling

Raw coal from the existing stockpile is screened to provide 1 x 1/4 inch feed for the ACCP process. Coal rejected by the screening operation is conveyed back to the active stockpile. Properly sized coal is conveyed to a 1,000 ton raw coal storage bin which feeds the process facility.

Emission Control

The fugitive dust from the coal cleaning system is controlled by placing hoods over the generation sources and conveying the dust laden air to fabric filter(s). The bag filters can remove 99.99 percent of the coal dust from the air before discharge. All fines report to a fines handling system than can briquette or cool the fines for product sales or make a slurry for disposal.

Sulfur dioxide emission control philosophy is based on injecting dry sorbent into the ductwork to minimize the release of sulfur dioxide to the atmosphere. The sorbent, sodium bicarbonate, is injected into the first stage dryer gas stream as it leaves the first stage dryers to maximize the potential for sulfur dioxide removal while minimizing reagent usage. The sorbent, having reacted with sulfur dioxide, is removed from the gas streams in the particulate removal systems. A 60 percent reduction in sulfur dioxide emissions should be realized.

Heat Plant

The heat required to process the coal is provided by a natural gas fired process furnace. This system is sized to provide a heat release rate of 58 MM BTU/hr. Process gas enters the furnace and is heated by radiation and convection from the burning fuel. Process make gas from coal conversion is used as fuel in the furnace. A commercial scale plant would most likely use a coal fired process furnace due to the much lower energy cost of coal.

Heat Rejection

Heat rejection from the ACCP is accomplished mainly by releasing water and flue gas to the atmosphere through the exhaust stack. The stack design allows for vapor release at an elevation great enough that, when coupled with the vertical velocity resulting from a forced draft fan, maximize the dissipation of the gases. Heat removed from the coal in the coolers is rejected using an atmospheric induced-draft cooling tower.

Utility and Ancillary Systems

The coal fines that are collected in the conversion, cleaning and material handling systems are gathered and conveyed to a surge bin. The coal fines are then briquetted and returned to the product stream.

The common facilities include a plant and instrument air system, a fire protection system, and a fuel gas supply and distribution system.

The power distribution system includes a 15 KV service, a 15 KV/5 KV transformer, a 5 KV motor control center, two 5 KV/480 V transformers, two 480 V load distribution centers, and six 480 V motor control centers.

Control of the process is fully automated including dual control stations, dual programmable logic controllers, distributed plant control, and data acquisition hardware.

PRODUCT CHEMISTRY

Rosebud SynCoal's Advanced Coal Conversion Process yields a synthetic solid fuel that represents an evolutionary step in the coalification process. Western lignite and sub-bituminous coals are converted by the thermal environment of the ACCP to a higher rank fuel.

The ACCP changes the chemical composition and structure of the coal feedstock. The changes include:

- Increased higher heating value;
- Increased aromaticity;
- Increase fixed carbon;
- Decreased moisture content;
- Decreased sulfur content per million Btus;
- Decreased ash content per million Btus;
- Decreased hydrogen to carbon ratios;
- Decreased oxygen to carbon ratios; and
- Decreased oxygen functional groups.

The above changes are the result of the thermo-chemical reactions induced by the ACCP and result in the upgraded synthetic coal product.

The average analyses of the coal feedstock and upgraded product from the demonstration plant are shown in Table 1. The first section of the table shows standard proximate and ultimate coal analyses of the coal feedstock and the synthetic coal product. The second section of the table shows petrographic and additional analysis showing the upgrading of coal through the process.

Moisture is essentially eliminated from the coal during the ACCP. This moisture removal is due to thermal dehydration of the coal particle and the chemical condensation reactions which the feedstock experiences during its residence in the high temperature environment of the second-stage reactor bed.

The moisture-free analysis of the feedstock and the upgraded product also show that, to a large extent, both the volatile matter and the fixed carbon content is retained in the SynCoal product. This phenomenon is significant and desirable, because normally raw coal, when subjected to the temperatures of the ACCP, would undergo devolatilization and substantial gasification.

The reduction in total sulfur is due primarily to the mechanical removal of pyrites during the cleaning step. However, the ability to remove these pyrites is a result of the chemical repolymerization and consequent shrinkage of the organic components of the coal, which causes fracture release of the ash or mineral components. A small amount of organic sulfur is volatilized from the coal in the form of hydrogen sulfide (H_2S) during the upgrading process.

PROJECT STATUS

Construction of Rosebud SynCoal's ACCP Demonstration Facility was completed during the first quarter of 1992 at a total cost of approximately \$35 million. Initial equipment startup was conducted from December 1991 through March 1992. Initial operations discovered the normal variety of equipment problems. The project's startup and operations groups worked together to overcome the initial equipment problems and achieve an operating system. The fines handling equipment was undersized originally and required a significant modification to expand the capability of this system. This modification was completed in August 1993. The lack of fines handling capacity prevented the facility from achieving full production rate and limited operating hours due to frequent fines handling equipment failures. The new fines handling system is expected to allow full production and more reliable operations.

The SynCoal® product has displayed a tendency towards self heating that was not expected. The project's technical and operating team continues to follow an extensive process testing program in order to determine the cause of the product's lack of stability. A number of approaches have been partially successful; however, to date, the demonstration product has not met the level of resistance to spontaneous combustion that was apparent in the earlier pilot plant work. This has reduced the storage life and as a result delayed the full-scale test burn program; therefore, a more limited test burn program is being planned at Montana Power's Corette station. A significant amount of handling and storage testing has been conducted in preparation for the anticipated full-scale test burn program. The results from these tests have been positive and the project team is looking forward to moving on with the full-scale combustion test program.

SynCoal's engineering team has been developing a proprietary product stabilization process step which has shown good promise at bench scale. Currently, a 500 pound per hour reactor is being tested and, if successful, a modification to the demonstration plant is planned for next year.

PROJECTIONS FOR THE FUTURE

The Rosebud Syncoal Partnership intends to commercialize the process by both preparing coal in their own plants and by licensing to other firms. The target markets are primarily the U.S. utilities, the industrial sector and Pacific Rim export market. Current projections suggest the utility market for this quality coal is approximately 60 million tons per year. The Partnership's goal is to start construction on a commercial facility designed to produce 3 million tons per year in 1995.

CONCLUSION

The ACCP is a relatively simple, low pressure, medium temperature coal drying and conversion process. The synthetic upgraded coal product exhibits the characteristics of reduced equilibrium moisture level, reduced sulfur content and increased heating value. The SynCoal product retains a majority of its volatile matter and demonstrates favorable ignition characteristics.

Although some difficulties have been encountered, SynCoal's technical and operating team are resolving the initial problems. The ACCP Demonstration program is continuing with a complete team effort involving all three of the major participants. It is expected that the ACCP demonstration will continue to produce test results over the next couple of years.

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SynCoal® is a registered trademark of the Rosebud SynCoal Partnership.

TABLE 1

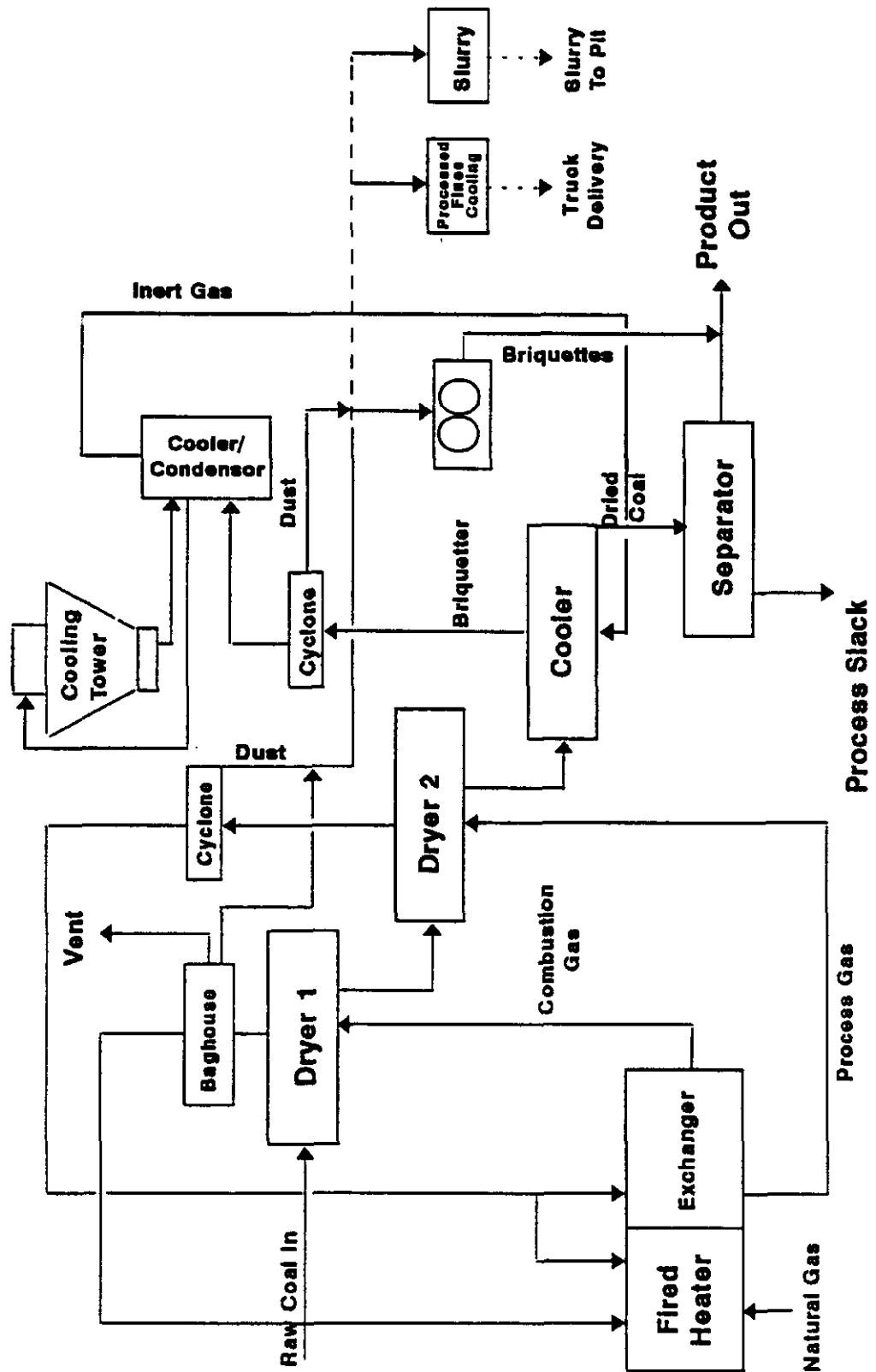
FEEDSTOCK AND SYNCOAL ANALYSES

<u>Proximate Analysis</u>	ROSEBUD MINE			
	<u>Rosebud Feedstock</u>	<u>MF*</u>	<u>SynCoal* Product</u>	<u>MF*</u>
% Moisture	24.1	--	1.0	--
% Volatile Matter	27.4	36.1	37.6	38.0
% Fixed Carbon	37.1	48.9	51.6	52.0
% Ash	11.4	15.0	9.7	9.9
BTU/lb.	8,421	--	11,832	--
% Increase in BTU/lb.			40.51	
<u>Ultimate Analysis</u>				
% Carbon	49.18		67.71	
% Hydrogen	6.57		5.20	
% Oxygen	30.99		15.78	
% Nitrogen	0.69		1.04	
% Sulfur	1.18		0.48	
% Organic Sulfur	0.50		0.40	
<u>Petrographic Analysis</u>				
% Huminite	77		81	
% Exinite	5		2	
% Inertinite	18		14	
Reflectance	0.42		0.51	
Surface area (cm ² /g)	288		55**	
H/C Ratio	1.60		0.92*	
O/C Ratio	0.24		0.09*	
Apparent Aromaticity		0.46		0.66*
% COOH	0.74		0.53*	
<u>Classification</u>				
ASTM C	Sub-bituminous C		High-volatile bituminous	

* MF indicates moisture free proximate analysis of feedstock and Coal Product.

** Indicates increased coal rank of Coal Product.

Process Flow Diagram



Flowdgm

START-UP AND OPERATION OF THE ENCOAL MILD COAL GASIFICATION PROJECT

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ABSTRACT

ENCOAL Corporation, a wholly owned subsidiary of SMC Mining Company, which is a subsidiary of Zeigler Coal Holding Company, has completed the start-up and initial operation of its 1000 ton per day Liquids From Coal (LFC) plant at Triton Coal Company's Buckskin Mine near Gillette, Wyoming. The plant has now produced several thousand tons of Process Derived Fuel (PDF), an upgraded coal product similar to a bituminous coal with very low sulfur. In addition, about 5000 bbls. of Coal Derived Liquid (CDL) have also been produced. CDL resembles a very low sulfur #6 fuel oil.

The plant has completed 15 runs and logged over 1400 hours of operation on Powder River Basin (PRB) coal. Some major pieces of equipment have run for more than 2300 hours. Most of the objectives of these runs have been related to plant testing, equipment shakedown and data gathering. Small quantities of CDL have been shipped to a customer, but no PDF has been delivered. It has all been used for laboratory and on site testing. The plant is currently shut down for a major modification - the addition of a continuous product finishing step that has only been done by batch methods so far.

This paper summarizes the project activities to date. A brief discussion of background information including the plant and process design is presented. Also included is a discussion of the modifications to the LFC plant already completed or underway. While no final conclusions can be drawn at this time as to the commercial application of the LFC technology, a summary of the operating results and product testing is presented.

BACKGROUND INFORMATION

Objectives

Beneficiated low sulfur Powder River Basin subbituminous coals should be one component in the strategy to reduce sulfur dioxide emissions from power plants throughout the world. In the ENCOAL Project, beneficiation is being accomplished by application of the Liquids From Coal (LFC) process. LFC Technology uses a mild gasification process, or mild pyrolysis as some know it, to produce a liquid fuel as well as a solid fuel. Thus dependence on imports of foreign oil could also be reduced by the installation of commercial scale LFC plants.

ENCOAL's overall objective for the Project is to further the development of full sized commercial plants using the LFC Technology. In support of this overall objective, the following goals were established:

- Provide sufficient products for full scale test burns
- Develop data for the design of future commercial plants
- Demonstrate plant and process performance
- Provide capital and operating cost data
- Support future LFC Technology licensing efforts.

This paper highlights several areas of immediate interest to potential customers and licensees. The first is the status of the ENCOAL plant and the operating experience so far. A second area is the product properties from recent long, continuous runs. Another area includes the results of combustion tests on samples taken from some of the initial ENCOAL Plant runs. In addition, the LFC Technology is reviewed with emphasis on the process steps successfully demonstrated.

General Description

ENCOAL Corporation is a wholly owned subsidiary of SMC Mining Company (SMC) which in turn is a subsidiary of the Zeigler Coal Holding Company. ENCOAL has entered into a Cooperative Agreement with the United States Department of Energy (DOE) as a participant in Round III of the Clean Coal Technology Program. Under this agreement, the DOE is sharing 50% of the cost of the ENCOAL Mild Coal Gasification Project. A license for the use of LFC Technology has been granted to ENCOAL from the technology owner, TEK-KOL, a partnership between SGI International of La Jolla, California and SMC Mining Company.

The ENCOAL Project encompasses the design, construction and operation of a 1,000 ton per day mild coal gasification demonstration plant and all required support facilities. The Project is located near Gillette, Wyoming at Triton Coal Company's Buckskin Mine. Existing roads, railroad, storage silos and coal handling facilities at the mine significantly reduced the need for new facilities for the Project.

A substantial amount of pilot plant testing of the LFC process and laboratory testing of PDF and CDL was done.^[1] The pilot plant tests showed that the process was viable, predictable and controllable and could produce PDF and CDL to desired specifications. Key dates and activities in bringing the project from the pilot plant stage to its current status are:

- Through early 1987: Development of the LFC process by SGI.
- Mid 1987: SMC joined with SGI on further development.
- Mid 1988: Feasibility studies, preliminary design, economics and some detailed design work by SMC.
- June 1988: Submittal of an application to the State of Wyoming for a permit to construct the plant - Approved July 1989
- August 1989: ENCOAL Project submitted to the DOE as part of Round III of the Clean Coal Technology Program.
- December 1989: Project selected by the DOE for funding.
- September 1990: Cooperative Agreement signed. Contract awarded to The M. W. Kellogg Company for engineering, procurement and construction.
- October 1990: Ground breaking at the Buckskin Mine site.
- July 1991: Basic design work completed and construction well underway.
- April 1992: Mechanical completion - commissioning begun.
- June 1992: First 24 hour run in which PDF and CDL were produced.'
- November 1992: SMC Mining Company and its subsidiaries, including ENCOAL, acquired by Zeigler
- April 1993: ENCOAL achieves two week continuous run
- June 1993: Plant shut down for major modifications.

The plant produces 500 tons/day of a solid Process Derived Fuel (PDF), which has the high heat content of Eastern coals but with low sulfur content, and 500 barrels/day of a Coal Derived Liquid (CDL), which is similar to a low sulfur Number 6 fuel oil. While CDL is different from petroleum derived oils in its aromatic and oxygen content, it has a low viscosity at operating temperatures and is comparable in flash point and heat content. The plant is supplied at the rate of 1,000 tons/day of subbituminous PRB coal.

Not a pilot plant or a "throw-away", ENCOAL's processing plant is designed to commercial standards for a life of at least 10 years. It uses commercially available equipment as much as possible, state of the art computer control systems, BACT for all environmental controls to minimize releases and a simplified flowsheet to make only two products matched to existing markets. The intent is to demonstrate the core process and not make the project overly complicated or expensive.

The ENCOAL Project is demonstrating for the first time the integrated operation of several unique process steps:

- Coal drying on a rotary grate using convective heating
- Coal devolatilization on a rotary grate using convective heating
- Hot particulate removal with cyclones

- Integral solids cooling and deactivation/passivation
- Combustors operating on low Btu gas from internal streams
- Solids stabilization for storage and shipment
- Computer control and optimization of a mild coal gasification process
- Dust suppressant on PDF Solids.

The product fuels are expected to be used economically in commercial boilers and furnaces and to reduce sulfur emissions significantly at utility and industrial facilities currently burning high sulfur bituminous fuels or fuel oils.

Process Description

Figure 1 is a simplified flow diagram of ENCOAL's application of the LFC Technology. The process involves heating coal under carefully controlled conditions. Nominal 3" x 0" run-of-mine coal is conveyed from the existing Buckskin Mine to a storage silo. The coal from this silo is screened to remove oversize and undersize materials. The 2" x 1/8" sized coal is fed into a rotary grate dryer where it is heated by a hot gas stream. The residence time and temperature of the inlet gas have been selected to reduce the moisture content of the coal without initiating chemical changes. The solid bulk temperature is controlled so that no significant amounts of methane, carbon monoxide or carbon dioxide are released from the coal.

The solids from the dryer are then fed to the pyrolyzer where the temperature is further raised to about 1,000°F on another rotary grate by a hot recycle gas stream. The rate of heating of the solids and their residence time are carefully controlled, because these parameters affect the properties of both solid and liquid products. During processing in the pyrolyzer, all remaining free water is removed, and a chemical reaction occurs which results in the release of volatile gaseous material. Solids exiting the pyrolyzer are quickly quenched to stop the pyrolysis reaction, then are further cooled indirectly and transferred to a surge bin. Because the solids have no surface moisture and, therefore, are likely to be dusty, a dust suppressant is added as PDF leaves the product surge bin.

The gas produced in the pyrolyzer is sent through a cyclone for removal of the particulates and then cooled to stop any additional pyrolysis reactions and to condense the desired liquids. Only the CDL is condensed in this step; the condensation of water is avoided.

Most of the residual gas from the condensation unit is recycled directly to the pyrolyzer, while some is first burned in the pyrolyzer combustor before being blended with the recycled gas to provide heat for the mild gasification reaction. The remaining gas is burned in the dryer combustor, which converts sulfur compounds to sulfur oxides. Nitrogen oxide emissions are controlled via appropriate design of the combustor. The hot flue gas from the dryer combustor is blended with the recycled gas from the dryer to provide the heat and gas flow necessary for drying.

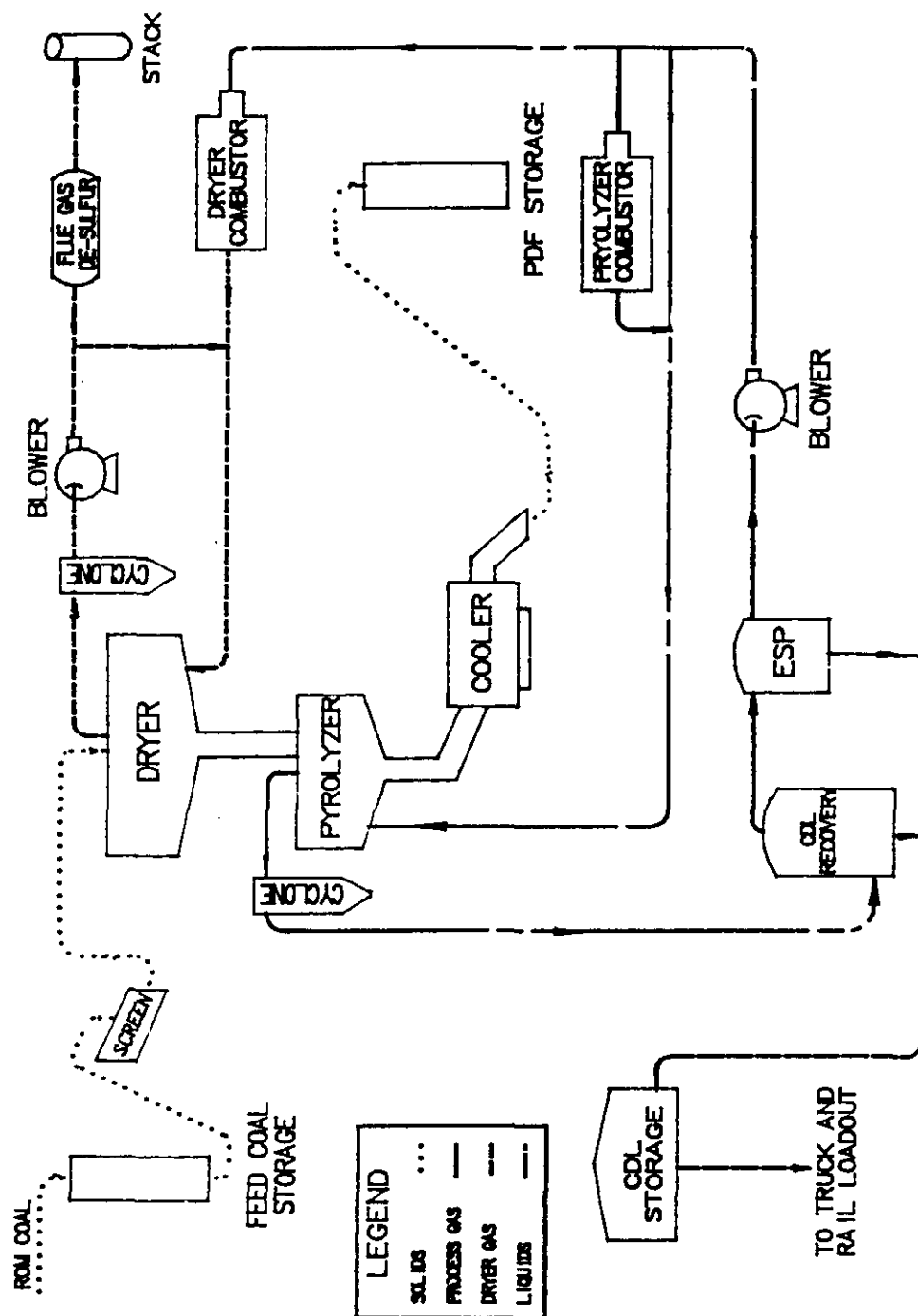


FIGURE 1. SIMPLIFIED FLOW DIAGRAM

The off-gas from the dryer is treated in a wet gas scrubber and a horizontal scrubber, both using a water-based sodium carbonate solution. The wet gas scrubber recovers the fine particulates that escape the dryer cyclone, and the horizontal scrubber removes most sulfur oxides from the flue gas. The treated gas is vented to a stack. The spent solution is discharged into a pond for evaporation. The plant has several utility systems supporting its operation. These include nitrogen, steam, natural gas, compressed air, bulk sodium carbonate and a glycol/water heating and cooling system.

Figure 2 is a plot plan for the ENCOAL Plant facilities including the Buckskin Mine rail loop which is used for shipping products.

START-UP AND MODIFICATIONS

During the final months of construction, ENCOAL developed a Start-up Plan and strategy for the first start-up and, separately, for subsequent start-ups. In general, the following steps are followed:

- Commissioning of plant or changes
- Complete pre-start checklist
- Complete valve alignment procedure
- Proceed with start-up sequence
- Perform run plan and testing
- Follow shut-down procedure

Seventy-eight steps over a period of 36 hours are required to achieve full operation on coal. Much of this time is spent ramping the temperatures up to a hot stand-by condition (ready for coal). The plant start-up is computerized and has been successfully tested on automatic through the start-up of all major equipment. Ultimately, the entire sequence of start-up and shut-down will be automated.

The start-up of the ENCOAL plant facilities has been typical of what one would expect from a first-of-its-kind technology application. Along with the 15 successful plant runs there have been many more false starts or planned partial starts. Valuable information is gained from every run, successful or not, and this information is carefully evaluated to define necessary equipment repairs, plant modifications and process adjustments.

A detailed review of equipment repairs and plant modifications through August 1992 has been presented^[1]. Since that time the need for further process and equipment modifications has become evident as start-up and initial operations have progressed. These can be grouped into the following categories:

- Electrostatic precipitators (ESP)
- Material handling system

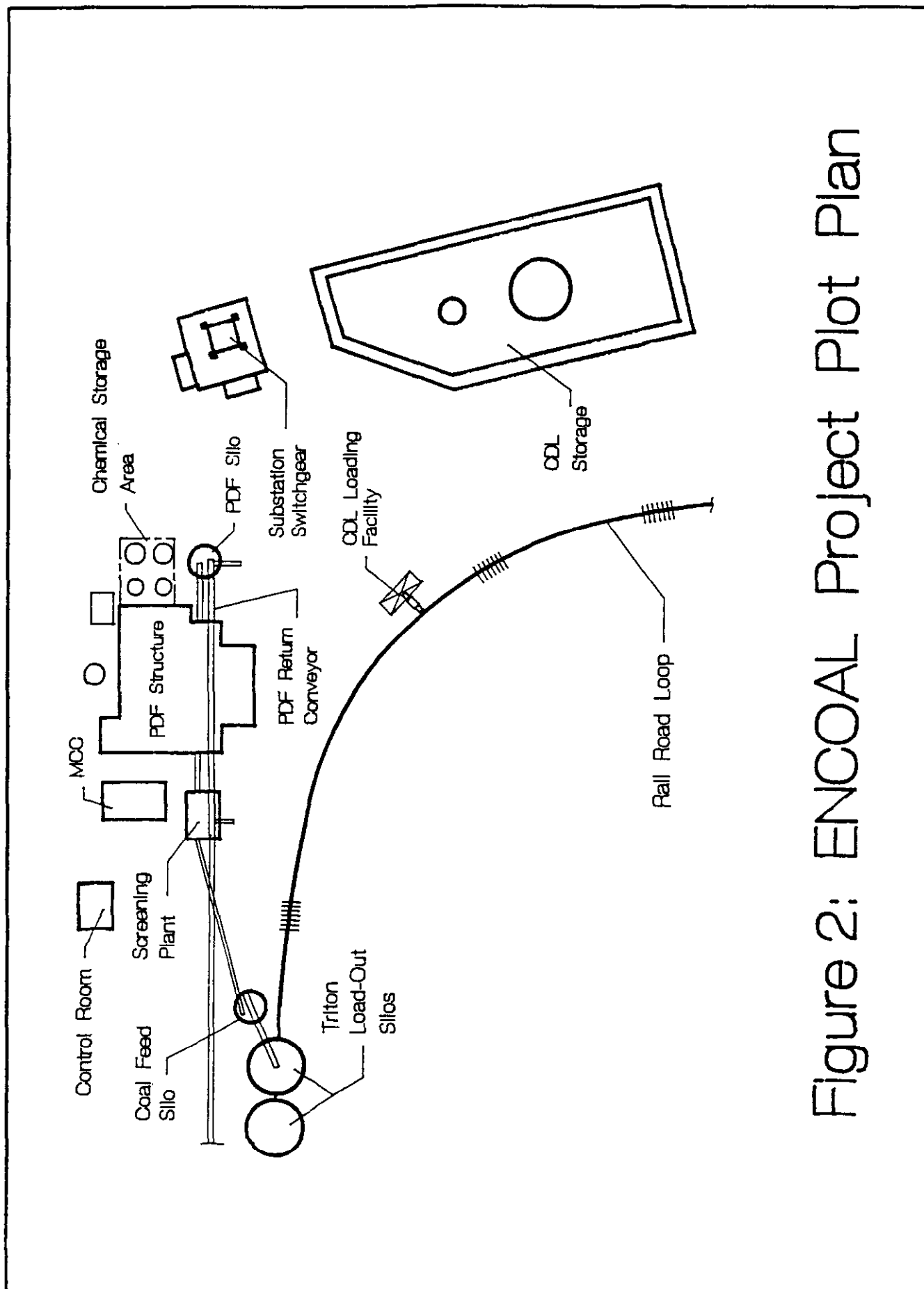


Figure 2: ENCOAL Project Plot Plan

- PDF quenching and cooling
- Dryer and pyrolyzer internal seals
- Combustor controls

Electrostatic Precipitators

Electric insulators in the three ESP's in the ENCOAL plant, in virtually all of the runs prior to April, 1993, have failed and caused plant shutdowns and upsets. Though at first thought to be an alignment problem, condensation of liquids on the insulators was eventually identified as the cause of failure. A new high alumina ceramic insulator was installed along with a new thermal blanket with temperature controls to keep the insulators hot and thus prevent condensation. In the April-June runs, for the first time, the plant ran for a total of 31 days without an insulator failure. Post shut-down inspection showed the new insulators to be clean and ready for continued service.

Material Handling System

No longer a significant problem, chute plugging and coal flow restrictions once caused plant shut-downs and interruptions. Modifications to the equipment as well as the start-up procedures have eliminated these problems. In the June run, the plant was successfully tested at the full 1000 ton per day feed rate. However, there remains a serious problem with spillage under the two vertical rubber-bucket conveyors (S-belts). Work is currently in progress on both S-belts to add a clean-up trench at the bottom and dribble control at the top.

PDF Quenching and Cooling

One of the areas in the process that had limited definition from the pilot plant studies and preliminary design work was the PDF quenching and cooling. Finishing and stabilization of the solid product is to take place in these steps, but this has proved to be elusive in actual practice. A plant test in January was set up specifically to determine if the existing plant equipment could be modified to achieve controlled cooling and stabilization. This test proved the opposite; the existing equipment was inadequate. Following the January run, a study was commissioned to develop alternative solutions. It was decided that additional equipment would have to be added to the plant.

The study group also recommended a series of laboratory tests and vendor equipment tests using actual PDF made in the ENCOAL plant to confirm the equipment selection and sizing. A plant test plan was developed for the April run that would also confirm on a batch basis at reduced plant throughput that the proposed solution would be effective. Several hundred tons of stable PDF was produced in the April run and stored in an open stockpile on site. Additional PDF was added to the pile in the June run. At the present time, about 1200 tons of PDF are stored in an open, uncompacted stockpile, with no evidence of self-heating after more than two months.

Based on the successful tests in April, ENCOAL proceeded with the design of the added unit operations and placed orders for the new equipment. The plant was shut down in June for construction with a planned completion and start-up of the new equipment late this year.

In a related part of the PDF quenching and cooling system, there has been a significant amount of dust and hydrocarbons present in the steam from the quenching step. This has repeatedly resulted in the plugging of lines and a steam condenser in the downstream water recovery system. A new stripping tower using water sprays has been added to remove the dust. The unit was tested in the April/June runs and proved to be very effective.

Dryer and Pyrolyzer Internal Seals

ENCOAL's process uses convective heating in the dryer and pyrolyzer. This is accomplished by passing hot gasses through a slotted, rotating grate upon which rests a bed of coal. The seal between the rotating grate and the vessel wall, which prevents the hot gas below the grate from bypassing the coal bed, is a blade attached to the rotating member immersed in a stationary tub of sand. See Figure 3 for the details. This seal design has proved to be very troublesome.

In particular, besides the higher than expected wear and maintenance problems in both units, the sand seal in the pyrolyzer does not allow operation at full differential pressure across the grate. In order to operate, the flow rate in the pyrolyzer loop must be reduced to avoid blowing out the sand in the seal. The lower gas flow rates result in loss of efficiency in the cyclone, dust carryover in the piping, solids in the CDL product and plugging of lines. In addition, less heat is transferred to the coal resulting in less severe pyrolysis. Attempts have been made to raise the on-gas temperature to compensate for the lower gas flow rate but this generates heavier CDL and lowers the liquid dew point in the off-gas. Condensation of liquid has occurred ahead of the quench column where it combines with the dust in the system creating unacceptable buildups in the ductwork.

ENCOAL is currently working with the vendor on alternate designs for the sand seal. In addition to modifications to the existing design, mechanical seals and alternate fluids are being evaluated. The plan is to implement any changes while the plant is down for the current construction.

Combustor Controls

Both of the combustors in the ENCOAL plant are required to burn very low Btu fuel gas, on the order of 50 Btu/ft³. A minimum amount of natural gas trim is added to provide heat under temperature control to the dryer and pyrolyzer. Oxygen in the flue gas must be kept very low, and CO and NO_x formation in the dryer combustor must be minimized. Control of these units is not a trivial matter. Through a series of hardware changes, mainly a system of properly sized and sequenced valves for combustion air, and rigorous software routines in the PLC based control computers, the combustors now operate very smoothly. They no longer require a full time operator's attention and no longer cause frequent plant shut-downs.

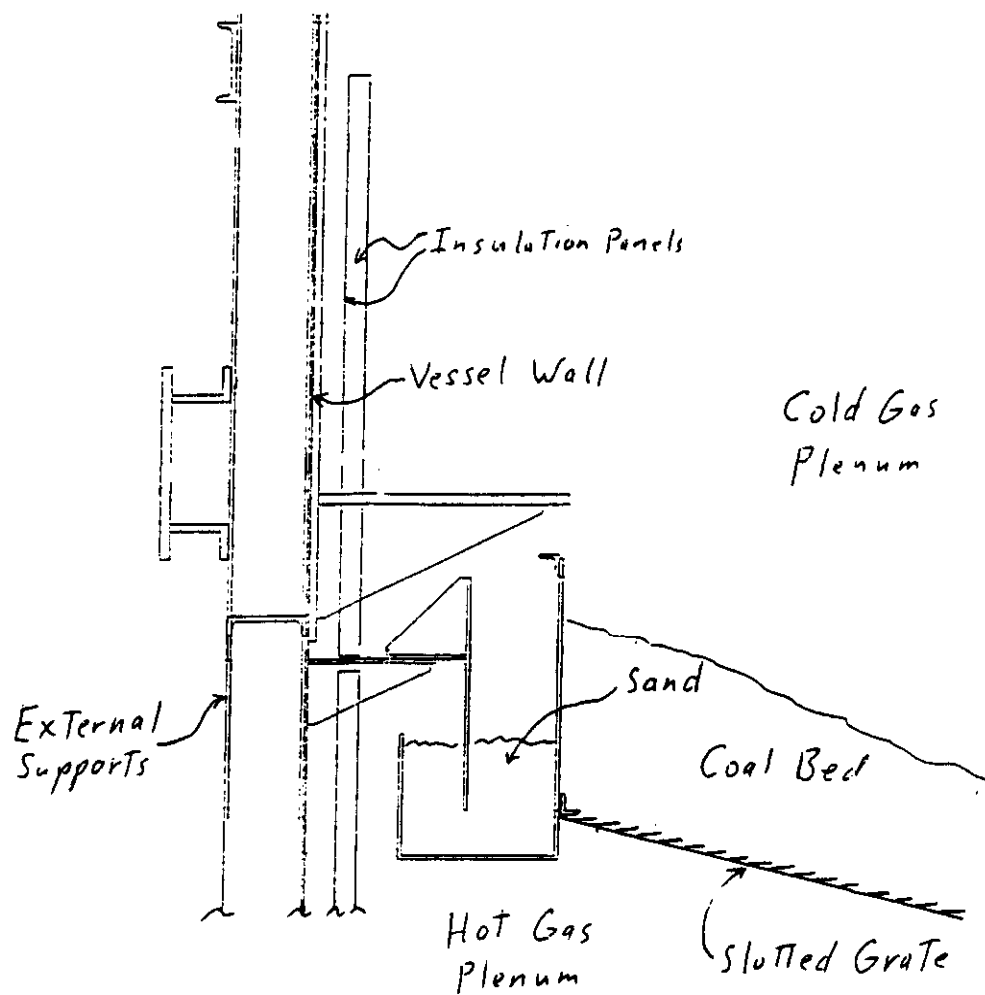


Figure 3. Detail of Dryer and Pyrolyzer Sand Seal.

PLANT OPERATING EXPERIENCE

Equipment Reliability

ENCOAL's LFC plant and facilities have now operated in an integrated mode producing PDF and CDL for more than 1400 hours. The total comes to more than 1800 hours adding the time products were not being made, but coal was entering the plant. Many of the major pieces of equipment, including the large blowers, combustors, dryer, pyrolyzer and cooler have operated for more than 2300 hours overall. Minor problems have been worked out for the most part and this equipment now operates reliably.

Process Controls - Workforce

Automation is a key goal of the project. Although most of the start-up and shut-down sequences are still hands-on, the plant operates in an integrated mode with the computer in full control of all equipment when the plant is on line. With only five operator set points, there is little need for operator intervention. Currently four operating technicians per shift run the plant plus one technical support person, one instrument/computer specialist and one supervisor. It is now evident that the plant can ultimately be operated with three operations technicians and one instrument specialist once the few remaining problems are worked out and plant testing is completed.

Carrying the automation to the next step, the start-up and shut-down sequences are already programmed and partially tested. This system should become operational over the next few runs. Ultimately a supervisory computer program should be able to close the loop on the plant and control the product qualities and recoveries based on on-line analysis of the feed coal and product streams. This program is operational now and is currently gathering data to fine tune its predictive algorithms. Computer control provides the means to optimize the revenue streams from a commercial plant as well as to safely control the plant operation.

Operating and Maintenance Costs

Operating and maintenance costs for the ENCOAL project are being tracked closely. This information is needed for estimating the costs of a commercial plant. So far, the costs for labor, chemicals, utilities, raw materials and administration are very close to the original projections. Although there have been significant plant changes and modifications as discussed above, these costs are still running below original projections. The cumulative cost for the operations phase of the Project (\$21,000,000 budget) is currently about 10% below the estimate, mostly due to lower run times on the plant. This is expected to come back to the budget projection once the plant reaches steady state operation.

Safety and Environmental Experience

Environmentally, the plant is exceeding all expectations for emissions control. The flue gas scrubber system is working very well and the particulates and sulfur emissions are half or less of the permitted values. The combustors are also performing very well so that the CO, NO_x and hydrocarbons are below the permitted levels. Having no process water discharge, the plant was designed to be environmentally benign. Wash down water from the coal side of the plant does report to a settling pond, as is typical of most coal operations.

Safety is the highest priority at ENCOAL. From the beginning, the plant was designed with safety in mind. Three HazOps reviews were conducted on the plant during the design and construction phase and all HazOps issues were addressed. A HazOps review was also done on the new product finishing unit operation. The plant interlock and alarm system are programmed for safety first. Because of this emphasis, the plant has proven time and again that it starts, stops and operates safely, and there have been many opportunities to test this due to the many "crashes".

An ambient air monitoring system was installed in the plant to warn against fugitive toxic or noxious gases. It has work well with the exception of nuisance alarms for SO₂. Ambient air surveys have been conducted by outside experts with no findings of harmful gases in concentrations even close to OSHA Threshold Limit Values. Odors were a problem for some people, so a vapor collection system with an activated carbon filter has been installed. Noise and heat in the plant have been much less of a problem than originally feared. Two additional ventilation fans have been added. Ear plugs are required for extended exposure inside the plant building.

Capacity and Availability

Third party testing of the plant stack and point sources has not yet taken place. This is because the plant has not been able to sustain design capacity for long periods. Coal has been processed at design rates and gas flow rates have reached design levels without coal in the unit, but the combination has not been sustainable because of the limitations discussed in the start-up section. Until the changes currently underway are completed, tested and proven, it is expected that the plant will operate at no more than 500 tons per day of feed, or 50% of design capacity.

During the last two extended runs, the plant availability exceeded 90% once the plant start-up sequence was initiated. Both of these runs were longer than two weeks, and in both cases the plant was intentionally shut down rather than crashing. Better weather was a factor in this success, but so were the many improvements to the plant.

Production

ENCOAL's LFC plant has now completed 15 runs where products were produced. PDF production from the April/June runs was about 4500 tons. An accurate figure is hard to determine because calibration of the plant weight measurement system is not yet completed and it is unreliable. CDL production is much more reliable because it is collected in a tank that can be measured. About 5500 barrels were produced in the April/June runs. Three tank cars of CDL have been shipped to a customer, but no PDF has been shipped. It has all been used for on-site and laboratory testing. Including cold coal runs, the plant has processed 17,400 tons of PRB coal from the Buckskin Mine.

Product recoveries from the feed coal have varied somewhat from the original projections. In the case of PDF, it has been lower. This is because more fines are generated in the process than expected and they are not recovered at the present time. CDL recovery is apparently higher than expected. However, the changes in yields are well within the error bands of the pilot plant data.

PRODUCT ANALYSIS

The ENCOAL LFC plant is still in the testing and initial operation mode and has not begun steady state operation. However, it has been demonstrated that product quality can be affected by plant operating conditions. Analyses of PDF are shown in Figure 4. Heating value, moisture, ash and sulphur fall in the range projected from pilot plant studies. Analyses of the CDL product are shown in Figure 6. The range of values is fairly broad in these initial CDL samples, but are close to or encompass the projected values. The analytical results for both products are discussed in more detail below.

PDF properties will be discussed first on an as-produced basis and then on a moisture and ash free basis. The former is of direct interest to customers with respect to utilization costs. The latter reveals how depth of pyrolysis impacts the organic matrix.

PDF As-Produced

PDF properties reflect quality variations of the feed ROM coal and the conditions of processing. During the lengthy steady state runs in April/June, process conditions were intentionally varied to determine the effect on PDF heating value, moisture content and residual volatility. Figure 4 shows data on 27 PDF samples collected during the April/June runs. The first 18 samples were collected in April, the rest in June.

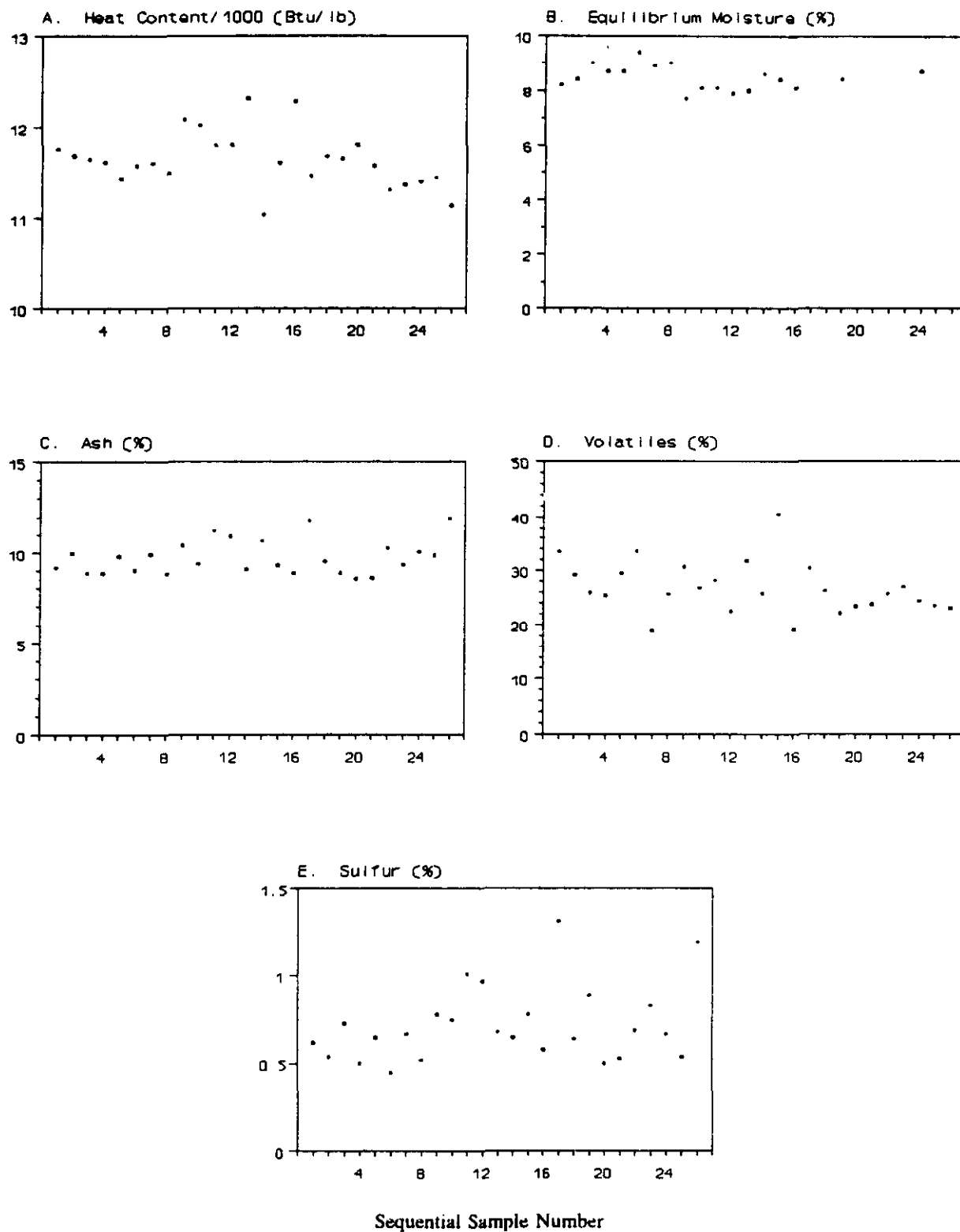


Figure 4. ENCOAL Mild Coal Gasification Project PDF Analytical Data April - June, 1993

Higher Heating Value (HHV). Heat content can be controlled somewhat in the plant by varying pyrolyzer loop operating conditions. As can be seen in Part A of Figure 4, the heat content of the produced material ranged above 12,000 Btu/lb, which is the projected value for operating the Plant in a commercial mode. The significance of moisture and ash free results will be discussed in the next section.

Moisture. Equilibrium moisture is shown in Part B of Figure 4. As-received moisture content and equilibrium moisture are affected by process conditions in the dryer pyrolyzer and PDF cooler. As received moisture has varied in the test so far from 2% to close to equilibrium values. During commercial operation of the Plant, the moisture content of PDF is projected to be in the range of 5 to 7%. Equilibrium moisture content was in the 8 to 9% range, these data being consistent with earlier laboratory data and prior ENCOAL Plant runs.

Ash. Because ash content from the Buckskin Mine runs around 5%, because roughly 2 tons of feed coal produce 1 ton of PDF and because all the ash stays with the solid product, an ash content of 10% is expected for PDF. Ash data for these runs is consistent as shown in Figure 4, Part C.

Volatiles. For most of the April/June runs, the target value for volatiles content was approximately 23%. Note that, from Figure 4, Part D, it *appears* that the target was attained only in the June part of the run. In fact, this is an artifact of the ASTM Volatiles analysis procedure, described as follows.

The ASTM procedure for determining volatiles content presents problems when PDF is analyzed. PDF is a sparking fuel. If normal ASTM procedures are followed, solid particles are ejected from the sample boat during the analysis. This phenomenon yields a greater weight loss than would have occurred from volatiles release only. The reported volatiles content is then higher than the actual value.

The samples taken in April were analyzed in routine fashion by a commercial laboratory. The samples taken in June were analyzed by the same laboratory, but with special attention being given to the volatiles analysis. Hence, the smaller scatter in volatiles results after the 18th sample.

However, using a different procedure based on thermogravimetric analysis developed by SGI International at their SGI Development Center Lab in Ohio, the volatiles content obtained is more reproducible and is generally lower than the ASTM results. Their results for volatiles from four of the same samples from the April run sent to the commercial labs vary from 13% to 18%.

Sulfur. Variability of sulfur in the product PDF is dependent on variability of sulfur in the feed, as long as the plant is run in a steady-state mode. Because sulfur in the feed coal was intentionally varied for the purpose of calibration of the plant's Gamma-Metrics Analyzers, there is significant variability of sulfur in the April/June run as shown in Figure 4, Part E.

PDF Moisture and Ash Free

Considering the properties of the produced PDF on a moisture and ash free basis reveals the effects of operating conditions on the coal organic matrix.

General. Table 1 compares some of these results between the feed coal and the product PDF. The number of feed coal samples is much smaller, 7 total, than the number of PDF samples. Because of the variation in depth of pyrolysis, variability of PDF properties is greater than the feed coal, as reflected in the standard deviation.

COMPARISON OF PDF WITH ROM FEED COAL MOISTURE AND ASH FREE BASIS				
	Feed Coal		Product PDF	
	Average	Std. Dev.	Average	Std. Dev.
Heating Value (Btu/lb)	12,740	85	13,840	220
Carbon (%)	73.4	0.6	84.0	1.6
Hydrogen (%)	5.5	0.1	3.6	0.2
Nitrogen (%)	1.1	<0.1	1.3	<0.1

Table 1. Comparison of PDF with ROM Feed Coal

On the average, the moisture and ash free heat content of the product PDF is 1,100 Btu/lb greater than the feed coal. This value is consistent with laboratory data. Also as expected, carbon content (ultimate analysis, not fixed carbon from proximate analysis) increased while hydrogen content decreased. While the nitrogen content increased, the value for PDF increased less than 10% over the feed coal, on a #Nitrogen/MMBTU basis.

Volatiles were not included in the table because of the analysis problems mentioned above for PDF. The decrease is still substantial, even with the error, at 47% volatiles for the feed coal versus 32% for the product PDF on a moisture and ash free basis. Sulfur is not included because of the high variation in feed coal sulfur content and relatively small number of feed coal samples taken.

Correlation of Data. While one would expect volatiles to vary inversely with the heat content on a moisture and ash free basis, the scatter in ASTM based analysis may preclude identifying a correlation on a routine basis. However, carbon content does correlate with the heat content on a moisture and ash free basis and either of these values may be a better indicator of the condition of the product PDF, when relying on routine analyses. The data are shown in Figure 5. Also included are the linear regression lines for all the data and also for just the PDF samples. A similar plot for volatiles versus heat content or carbon content on a moisture and ash free basis shows significant scatter, as indicated above.

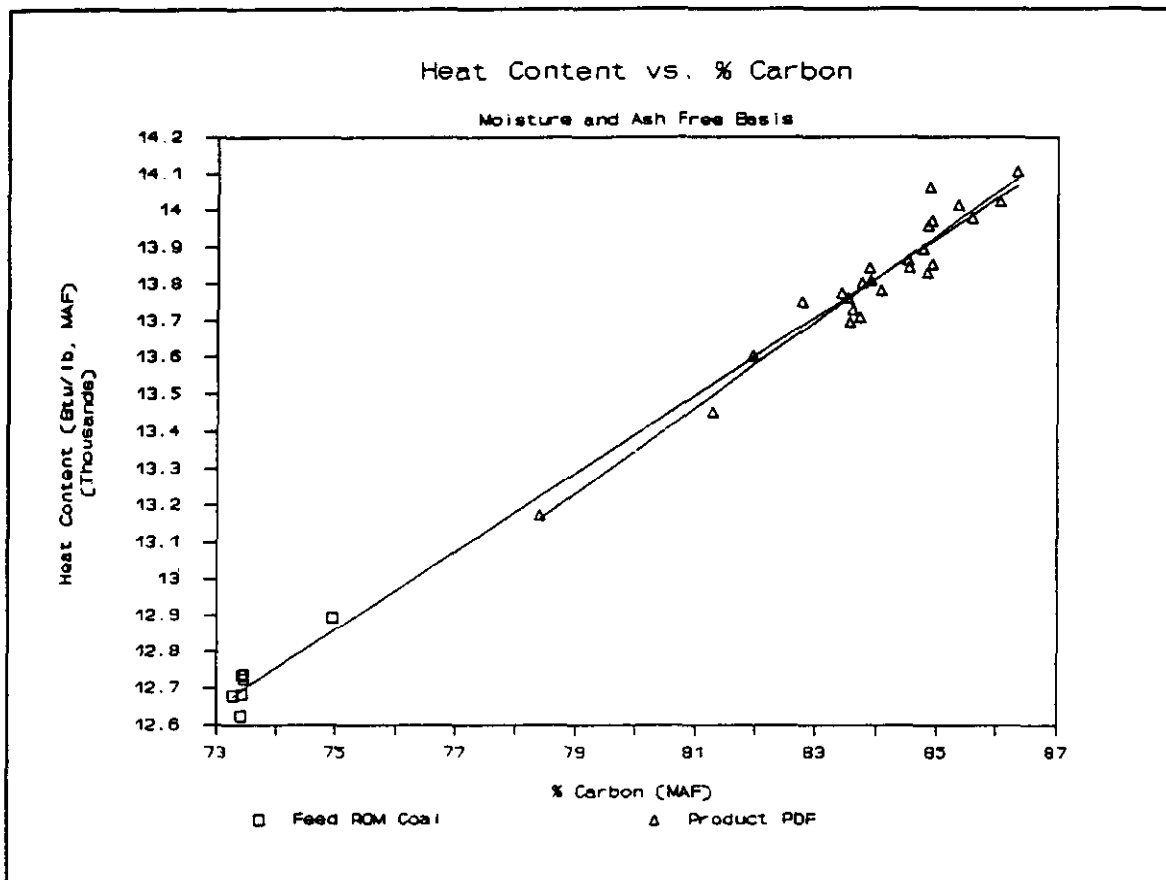


Figure 5. Heat Content vs. % Carbon.

CDL

General

While properties of PDF are essentially fixed in the pyrolyzer, those of the CDL are also influenced by operation of equipment in the pyrolysis gas loop, including the pyrolyzer cyclone, the quench tower and the electrostatic precipitators. In addition, because of the relatively large inventory of CDL in the quench tower, CDL properties take a long time to reach a new steady state when process or equipment operating conditions are changed. It may take as long as 24 hours for the CDL properties to reflect such operating changes.

Of the 15 CDL samples taken and analyzed, the first 12 were taken during April and the last 3 during June. Data taken on these samples are shown graphically in Figure 6.

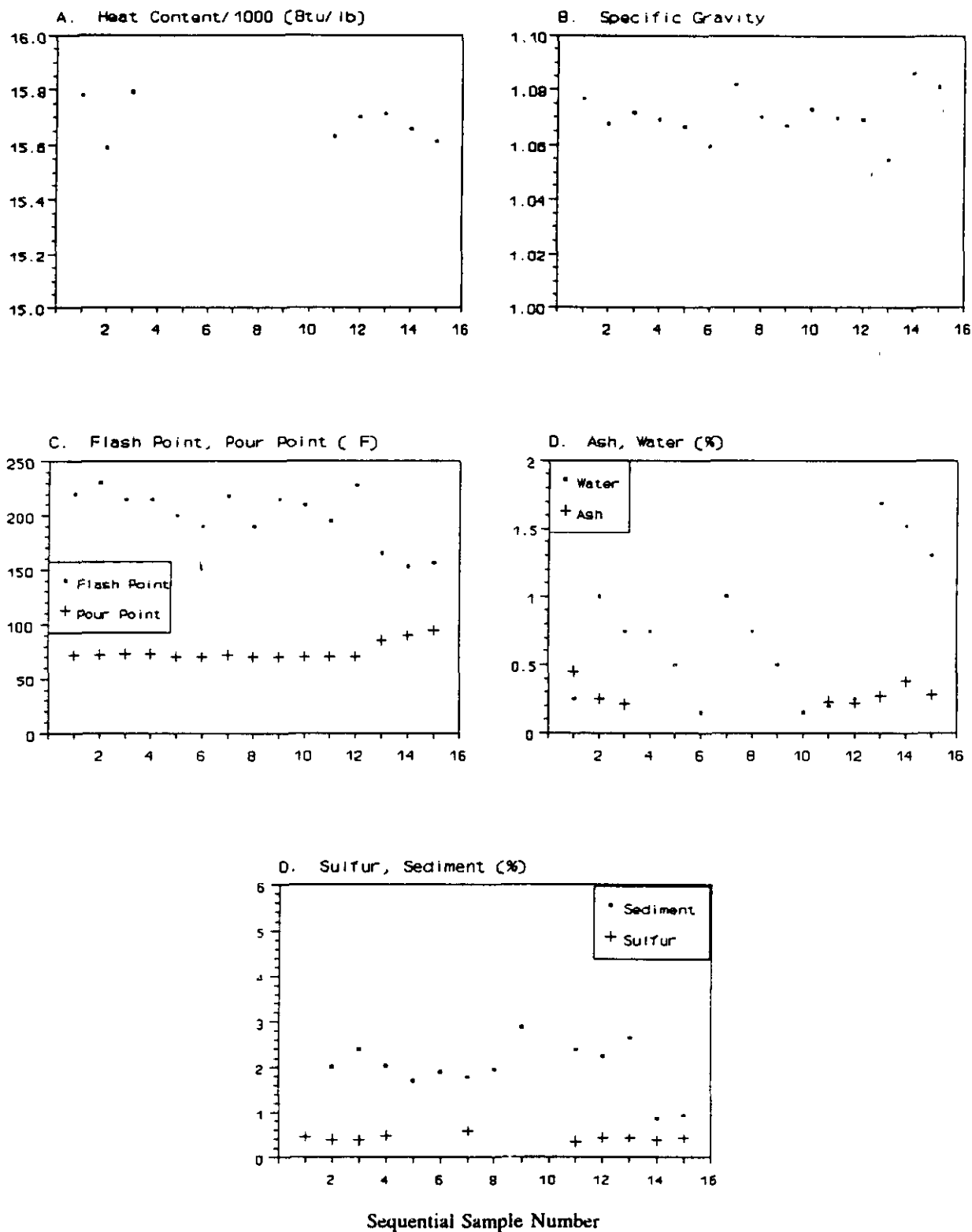


Figure 6. ENCOAL Mild Coal Gasification Project CDL Analytical Data April - June, 1993

Properties

The average heat content of the samples analyzed was 139,000 Btu/gal, slightly under the value of 144,000 Btu/gal projected for commercial operation of the Plant. The data are shown in Part A of Figure 6. Because the Plant was operated under pyrolysis conditions a little less severe than planned for commercial operation, this value is consistent with expectations.

Data for specific gravity are shown in Figure 6, Part B. The specific gravity averaged 1.07 (API Gravity = 0.61°). This is somewhat more dense than the projected 1.03.

Operation of the pyrolysis loop was changed between April and June as indicated by the flash point and pour point data, shown in Part C of Figure 6. The June samples show higher pour points and lower flash points relative to the April samples. This may be because the April data on pour points were in error.

Ash content and water content are shown in Part D of Figure 6. Ash content was less than 0.5% for all samples analyzed. Water content was more variable, being less than 1% for all the samples collected in April, but somewhat higher in samples collected in June.

Sulfur was quite consistent, varying from 0.35% to 0.45%, except for one sample at 0.58%. The average #Sulfur/MMBtu was 0.26, which compares favorably to a value of about 0.46 for low sulfur No. 6 oil. The sulfur data are shown in Part E of Figure 6, along with sediment data. Sediment results will reflect how much ash and fine coal particles are entrained in the pyrolysis gas and pass through the pyrolyzer cyclone. Most samples were between 1.7 and 2.9% sediment. Two samples were much higher at 5.1% and 11.4% and two samples were lower, being less than 1%. These last two low sediment values may represent, again, the different mode of operation in June versus April.

These data indicate that a liquid product can be produced with specifications close to what had been projected in laboratory tests. Furthermore, there appears to be some flexibility in affecting the liquids product by how the pyrolysis loop is operated. There is much more to be learned about the effects of plant operating parameters on liquid quality in future runs.

Product Shipments

Both PDF and CDL have been produced in the ENCOAL Plant as indicated above. To date, 1500 barrels of CDL have been delivered to TexPar Energy, Inc., which has contracted for the purchase of most of the CDL from the ENCOAL Plant. A PDF sample has been shipped for combustion testing at Shell Development Company. Results of these combustion tests are described below.

As discussed above, the plant is currently shut down for major modifications to add the finishing and stabilization equipment. The objective is to complete the construction work and test the system by the end of the year. When this objective is attained, production runs to supply customers for full scale testing will commence.

A contract is in place for initial test burns of PDF in some of Wisconsin Power and Light's (WP&L) cyclone boilers, both blended and unblended. Because the ash elemental composition for PDF is essentially the same as that of run-of-mine PRB coal and because these WP&L units can operate successfully on unblended PRB coal, ash viscosity is not expected to be a factor. Following the work with WP&L, tests are planned on pulverized coal-fired units.

Considering that partially devolatilized subbituminous coal in quantities sufficient for testing in commercial units has never been available before and that laboratory scale testing indicates significantly different flame properties compared with other fuels, there is much to look forward to in field tests.

PRODUCT EVALUATION

Factors in PDF Utilization

The unique nature of PDF, a devolatilized subbituminous coal, leads to the need to assess its utilization characteristics. There are several characteristics that are critical to potential users. Other factors need to be evaluated with respect to how readily PDF can be substituted for the design coal in any given unit. The quality characteristics that were deemed significant and were evaluated as being acceptable to proceed with the ENCOAL Project have been described previously^[2]. The source of material for these first evaluations was either PDF generated in the SGI pilot plant or dried PRB coal.

The ENCOAL plant has now produced PDF and CDL from each of 15 different runs over the last year. In October, 1992 some drums of PDF were shipped to Shell Development Company in Houston for laboratory combustion tests. Descriptions given below are based on these tests and will generally be described as being in comparison to run-of-mine PRB coal.

Coal quality characteristics that would render a new solid fuel useless to potential users are excessive dust, accelerated spontaneous combustion or an unstable flame.

Dustiness. Nuisance dust (particle sizes less than 100 microns) can be especially serious for coals with zero surface moisture. For PDF, a fuel with no surface moisture, control of nuisance dust generation was anticipated with the following measures. First, handling of samples from the pilot plant indicated the tendency to form nuisance dust was less than that of run-of-mine PRB coal. Second, the feed coal is screened to remove the minus 1/8th inch fraction in the ENCOAL plant. Third, provision was designed into the ENCOAL plant for applying a dust

control additive, designated as MK. MK was successfully demonstrated on dried coal in large scale tests (pile size, 100-200 tons) at the Buckskin Mine^[1].

In the preliminary results with PDF generated at the ENCOAL plant the amount of nuisance dust appears comparable to or less than run-of-mine PRB coal. However, the dosage of MK has not been optimized.

Spontaneous Combustion. PDF produced in pilot plant studies was stable with respect to spontaneous combustion. In fact, testing of these samples indicated that PDF would have a lower tendency for self-heating under ambient air conditions than run-of-mine PRB coal^[2]. At the present time, the PDF produced at the ENCOAL plant has not attained the same resistance to spontaneous combustion as the SGI pilot plant samples. Ongoing work at the ENCOAL plant is directed toward diminishing self heating of PDF in order to match the stability toward spontaneous combustion demonstrated by PDF samples generated in the pilot plant studies.

Flame Stability. The question of flame stability arises from the volatiles content of PDF. Results of combustion tests on PDF samples generated from the pilot plant have been reported^[2]. These samples included a 22% volatiles product and a 17% product. A sample of PDF from the ENCOAL plant has recently been tested in the same 100 lb/hour laboratory combustor. This sample had 22% volatiles.

The results are quite favorable, especially with respect to flame stability. In the tests on PDF pilot-plant samples, carbon monoxide levels were only slightly higher than the parent run-of-mine PRB coal and carbon burnout was equivalent to the run-of-mine PRB coal. No problems were noted with respect to pressure pulsation in the furnace. If the flame were unstable, increased pressure pulsation, which is associated with blowout of the flame and re-ignition of the fuel, would be expected. Furthermore, the flame was less luminous due to the lower volatiles content.

Three PRB coals, including Buckskin, were used in the series of tests reported here. These will be designated PRB1, PRB2 and Buckskin. Two lower sulfur Eastern bituminous coals were also run as part of blend tests. The two Eastern coals vary significantly, both in volatiles and sulfur content. These will be designated as E1 and E2. PDF from the ENCOAL plant was run unblended and as a blend with PRB2.

Furnace pressure is plotted as a function of time for a typical one hour period for several of the tests in Figures 7 and 8. Figure 7 compares unblended PRB1 with unblended PDF. Quite surprisingly, the variation in pressure is significantly *reduced* for PDF compared to the run-of-mine coal. These data correlate with the difference in appearance of the flames. The PDF flame is short and compact with a relatively fixed flame pattern. In contrast, the run-of-mine PRB coal flame is about twice as long, using the same burner setting, with a changing ill-defined flame pattern as is normal with a coal flame. If one did not know a solid fuel were being burned, the PDF flame would be described as a natural gas flame.

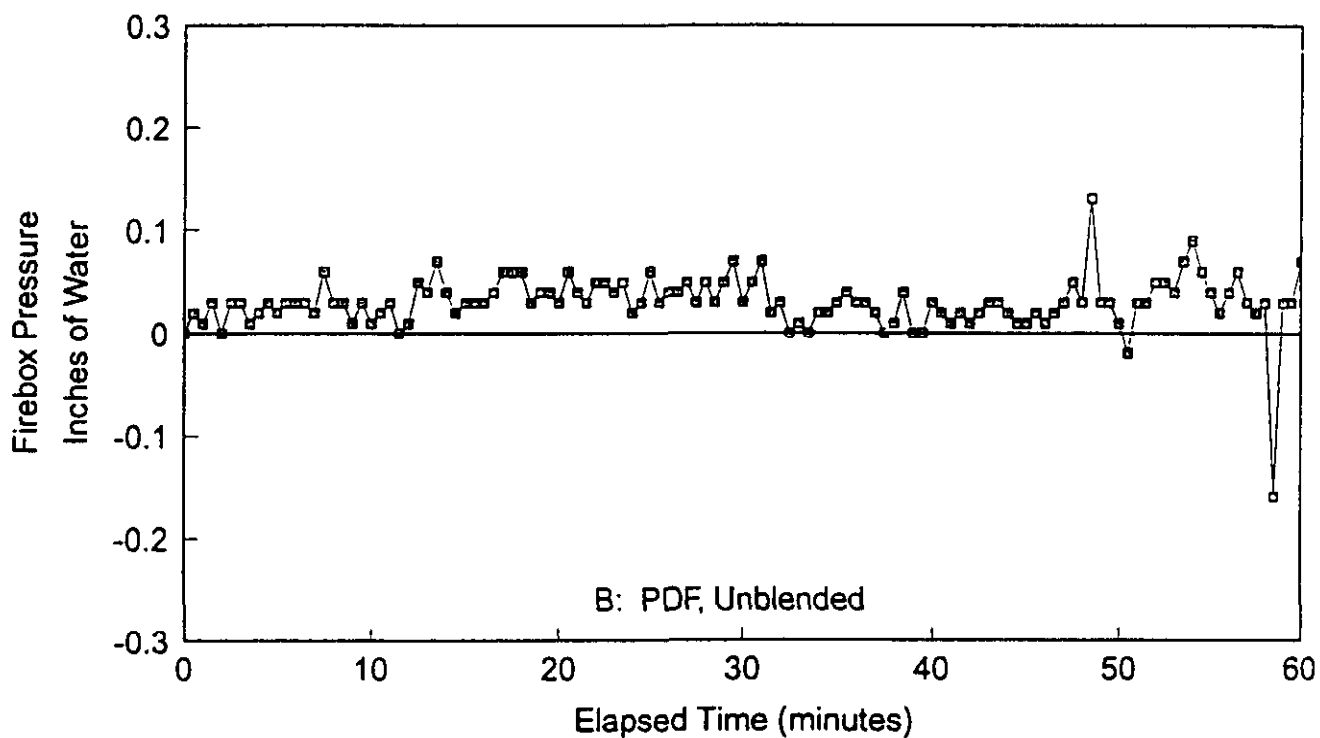
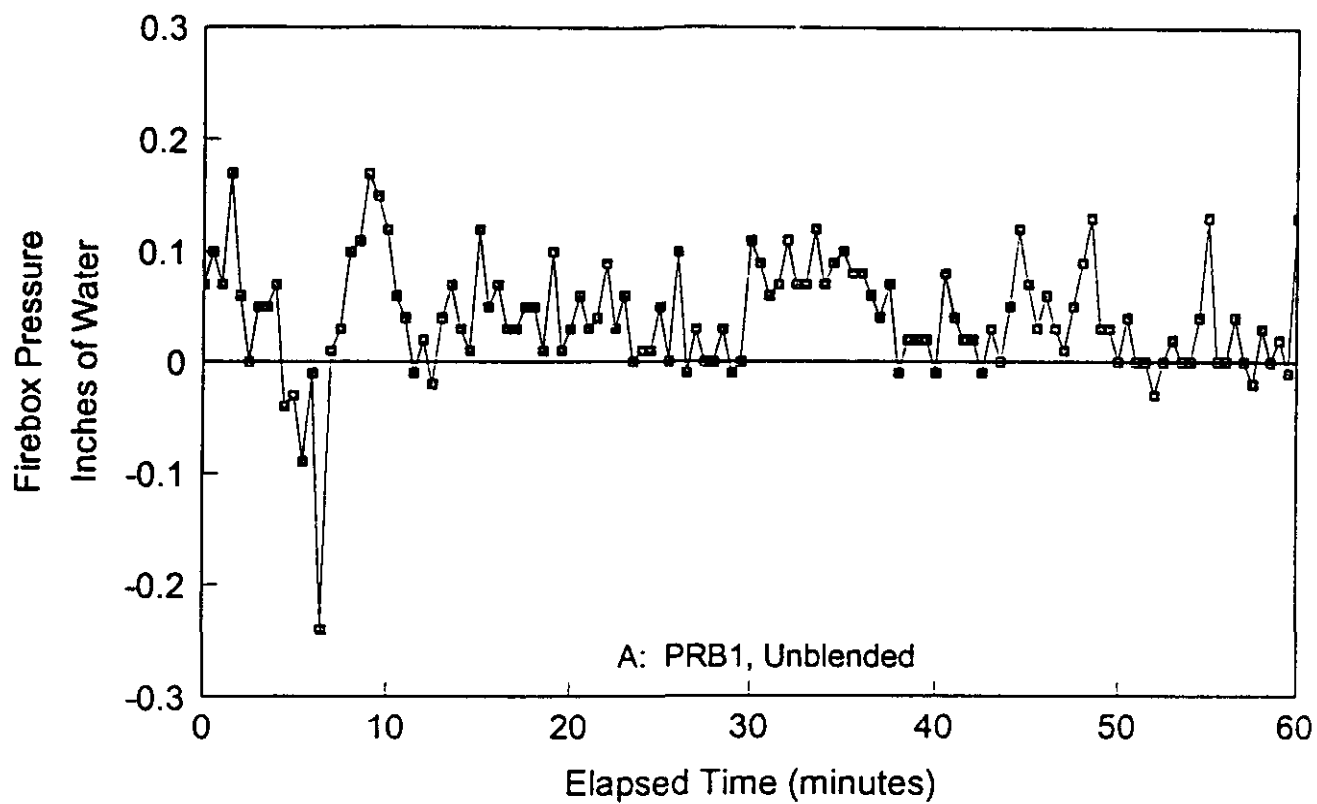


Figure 7. Furnace Pressure vs. Time for Typical One Hour Period for Unblended PRB1 and Unblended PDF

The blend test results for PRB2 are shown in Figure 8. These include a blend with 20% E1, another with 20% E2 and a third with 25% PDF. The blends show a somewhat reduced furnace pressure fluctuation relative to 100% PRB, but still distinctly greater than 100% PDF. The unexpected result is that the pressure fluctuations of the 25% PDF blend are quite low, comparable to the 100% PDF results. One can speculate, based on the blend tests, that PDF may enhance combustion when blended with other coals.

The flame for the two PDF samples obtained from the pilot plant had been less luminous than that of run-of-mine PRB coal. For the PDF sample from the ENCOAL plant, the flame luminosity was closer to that of a run-of-mine coal flame. It is believed that a lower volatiles PDF from the ENCOAL plant will also be less luminous than run-of-mine PRB coal.

Carbon monoxide data from this series of tests are shown in Table 2.

	<u>Buckskin</u>	<u>PRB1</u>	<u>PRB2</u>
PRB, Unblended	18*	N/A	
PDF (from ENCOAL) Unblended	16		
Blended with 25% PDF			13
Blended with 20% E1	8	6	9
Blended with 20% E2	25	28	21
*From previous tests			
N/A, Not available for this test			

Table 2. AVERAGE CARBON MONOXIDE LEVELS (ppm), TAKEN OVER ENTIRE TEST

CO values ranged from a low of 6 to a high of 28 ppm. As can be seen from the table, the value of 16 ppm for unblended PDF from the ENCOAL plant is in the range of values measured for PRB/Eastern coal blends. It can be inferred from these results that good combustion conditions exist in the flame. The data support the furnace pressure information indicating good flame stability. The data reported previously⁽²⁾ on PDF samples from the pilot plant show CO values ranging from 25 to 32 ppm. The slight difference between the results in the two test series could be due to a different burner setting or a higher furnace exit gas temperature (50°F to 150°F) for the recent tests on PDF from the ENCOAL plant versus the earlier tests on PDF samples from the pilot plant.

Other Factors. In addition to the above characteristics, that are critical to potential users, are others that determine PDF's utilized value. With respect to handling, these include moisture resorption, bulk density, grindability and flow attributes. Ash deposition, heat transfer and NO_x generation are of particular interest with respect to combustion.

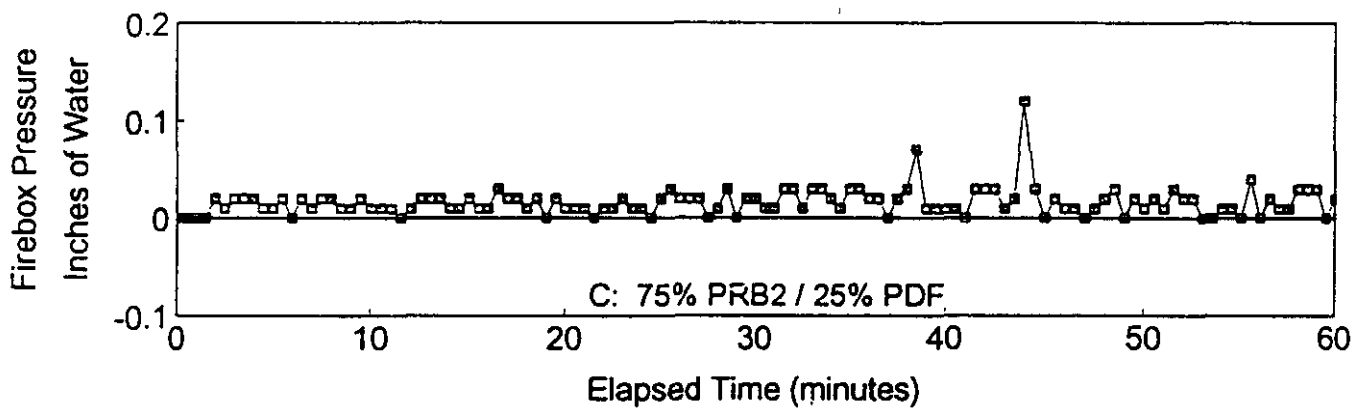
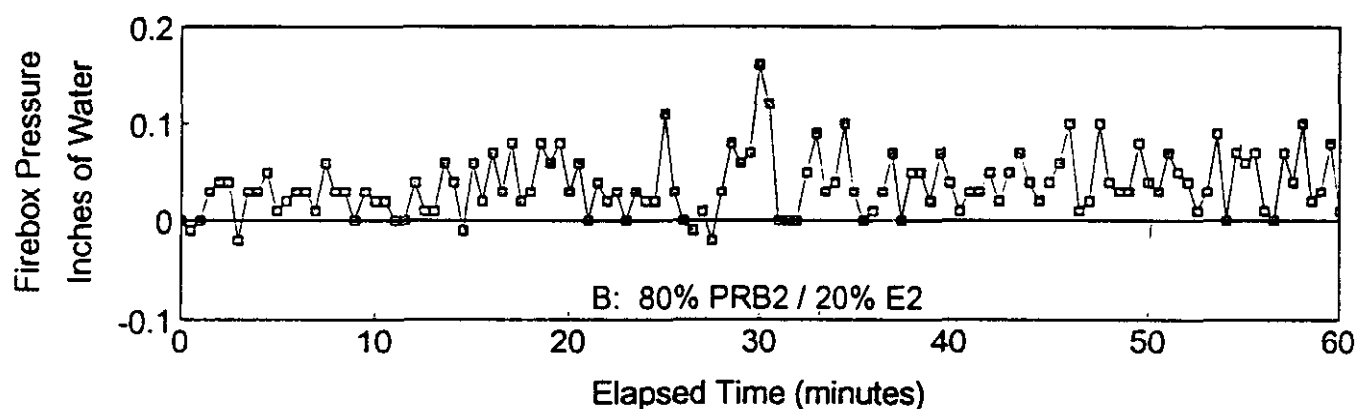
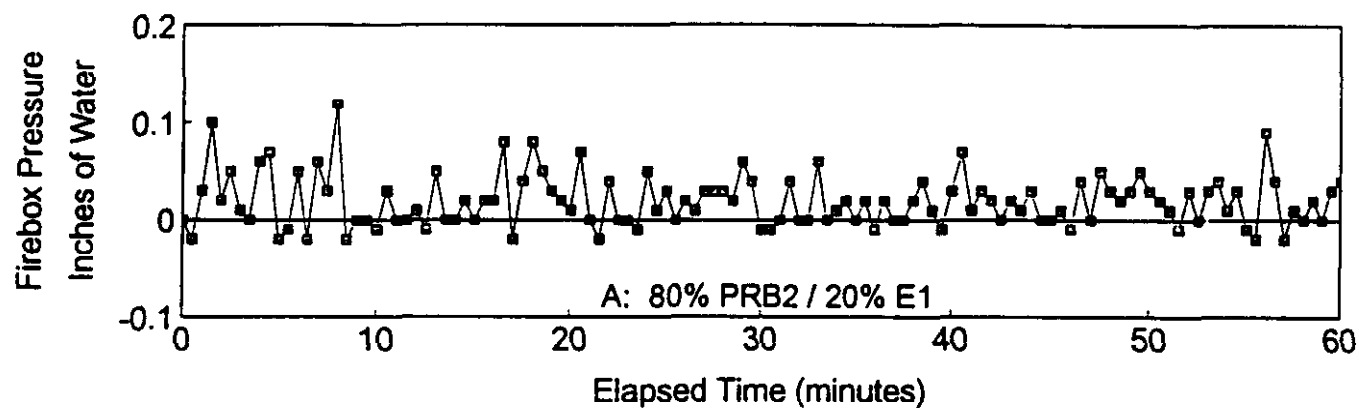


Figure 8. Furnace Pressure vs. Time for Typical One Hour Period for PRB2 Blends with E1, E2 and PDF

Because PDF is not yet being generated under steady state operation in the ENCOAL plant, the properties listed above have not been determined for commercially produced PDF. Moisture resorption was studied for PDF produced in the pilot plant and was determined not to be a significant factor^[2]. With respect to flow attributes, the ENCOAL plant samples recently tested in the combustion facility exhibited good flow characteristics, even though top size was generally less than ½ inch.

COMBUSTION

Radiant Heat Transfer

Because PDF is derived from PRB coal, it is natural to compare the two fuels, particularly in steam generators not designed for PRB coals. There are cases in which an increase in furnace exit gas temperature is experienced when burning run-of-mine PRB coals relative to a unit's design coal. This is generally described as throwing the heat back into the convective pass. Because of the light color of ash from PRB coals, this condition is sometimes characterized as "bright furnace". Predicting how PDF will perform in full scale units, compared with run-of-mine PRB coal, is a non-trivial exercise. A very brief description of some factors follows.

Testing of PDF from the ENCOAL plant in the laboratory combustor shows a 400°F higher temperature for PDF relative to run-of-mine PRB coal at one flame location (2700°F vs. 2300°F). The higher temperature for PDF is encouraging in that it represents up to 70% higher radiant heat generation for PDF relative to run-of-mine PRB coal. Two possible reasons for the measured flame temperature difference are: first, heating value and second, moisture content of the pulverized coal particles exiting the burner. Regarding the first reason, the moisture and ash free heating value for PDF is on the order of 1300 Btu/lb higher than that for run-of-mine PRB coal. With respect to the second major difference, some field data indicate that only about half the water content in run-of-mine PRB coal has evaporated by the time the pulverized particles exit the burner. This residual water content would help suppress the flame temperature.

Heat transfer is dependent on a number of factors including radiation from the flame, absorption of radiation in the cooler part of the flue gas and deposit reflective and insulating characteristics. A series of model calculations indicates the net effect of heat transfer for PDF relative to run-of-mine PRB coal can vary significantly depending on these various factors. Sufficient information on these parameters is not available to allow accurate prediction of heat transfer in full scale boilers.

For example, in Figure 9 is shown the predicted effect of flyash particle size on run-of-mine PRB coal and PDF. Only particle size and ultimate analysis were varied in the input data. The effect of doubling the particle diameter in this range is dramatically larger for PDF relative to run-of-mine PRB coal. These results were generated using a zero-dimensional model^[3]. The effect is likely due to the change in water concentration in the flue gas. Water is an effective

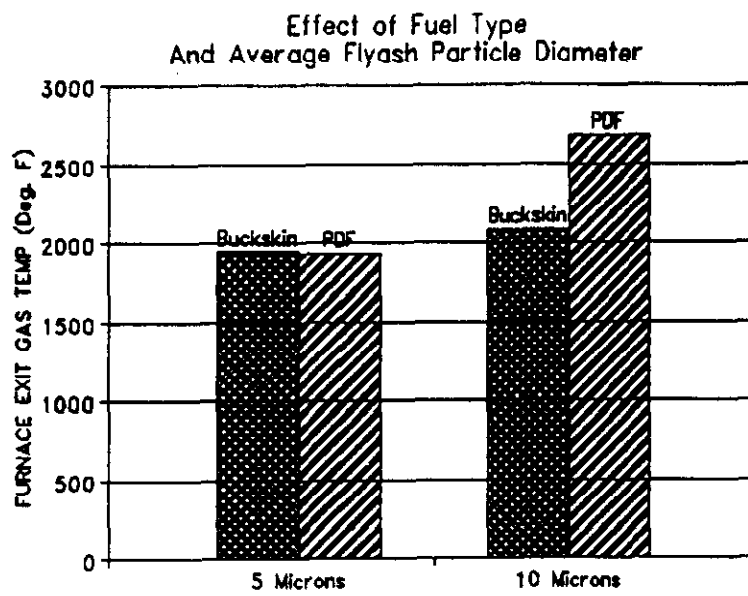


Figure 9A. Effect of Fuel Type and Average Flyash Particle Diameter

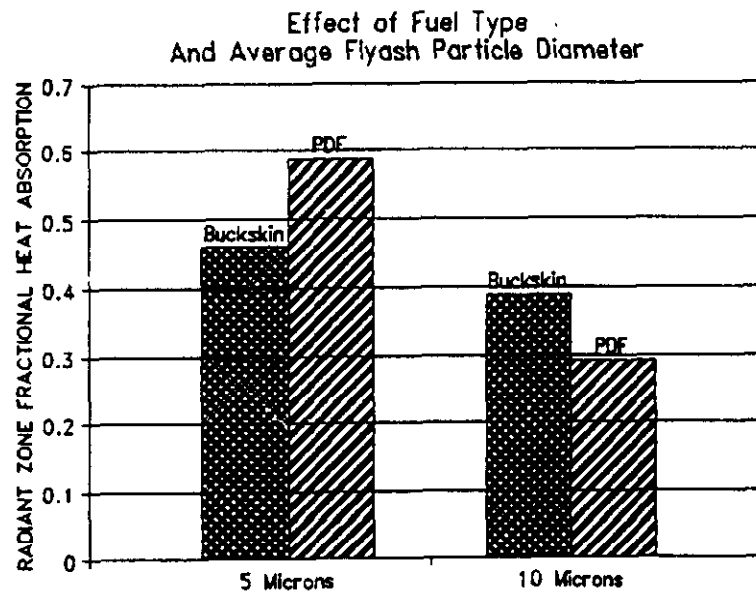


Figure 9B. Effect of Fuel Type and Average Flyash Particle Diameter

radiating component. However, the percentage of water (molar basis) in the flue gas is on the order of 13% for run-of-mine PRB coal compared to 7% for PDF, a significant difference. With the reduced water content, radiation from flyash particles becomes a more significant factor for PDF relative to run-of-mine PRB coal. There is also about 40% more ash for Buckskin PDF on a lb. ash/MMBtu basis compared to run-of-mine Buckskin coal.

Other factors, such as soot (not varied in these calculations) and char concentrations in the flue gas and heat transfer properties of ash deposits also have a strong effect.

Field testing, particularly in pulverized-fired units, will be particularly important from the standpoint of understanding radiation effects on heat transfer.

Ash Deposition

Ash elemental composition does not change appreciably during processing from the run-of-mine PRB coal feed coal to PDF in the ENCOAL plant. Ash loading in a steam generator will increase 35 to 40% on a lb/MMBtu basis considering that the weight percentage of ash will roughly double during processing. Thus, an initial prediction would be that ash deposition will increase for PDF relative to run-of-mine PRB coal. However, it can be inferred from tests in the laboratory combustor that other factors may come into play for PDF.

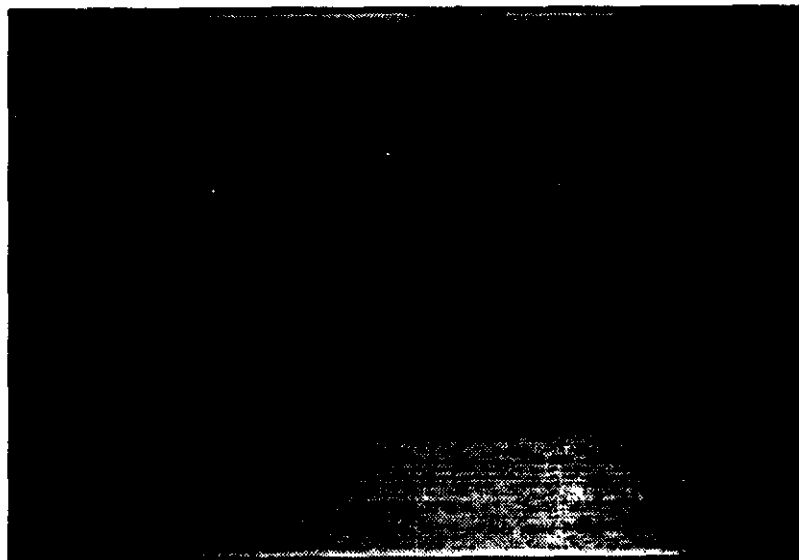
Deposits for PDF have a different appearance from run-of-mine PRB coal. On the waterwall panels, the deposits are more evenly distributed with less of the cauliflower-like deposits. Figure 10 shows the waterwalls at the end of the test before wallblowing, both for PDF and 100% PRB1. The spotty growing deposits shown for the 100% PRB1 sample also are observed for PDF. However, for PDF, they fall off under their own weight during the test. Only a small amount can be seen in the lower left hand corner.

In addition the ash from PDF seems to be more friable and to blow as readily as the run-of-mine PRB coal, which itself is easily removed by wallblowing. When blowing the waterwall panel, PDF deposits were readily knocked off at the lowest blowing pressure. Heat transfer to the waterwalls returned to initial values after wallblowing, confirming the observation of the ease of removing deposits by wallblowing. Decay of heat transfer versus time for PDF tracks that of run-of-mine PRB coal indicating that deposit buildup was not accelerated relative to PDF.

With respect to the superheater, the deposits for PDF seem to be larger than with Buckskin coal, but extremely light, as viewed on-line. Some of the PDF deposits fell off the superheater tubes while inserting the sootblower, before turning on the blower. The remaining deposits were easily removed. As with the waterwall data, heat transfer for PDF returned to initial values after sootblowing and decay of heat transfer tracks that of run-of-mine PRB coal.



A: PRB1, Unblended



B: PDF, Unblended

Figure 10. Waterwall Appearance at End of Test Prior to Wall Blowing

NO_x Generation

Generation of NO_x is dependent upon both fuel/air mixing and combustion gas temperature history and, therefore, is specific to furnace and burner configuration and operation. However, at least a comparison can be made between PDF and run-of-mine PRB coal in this combustion test facility (fast mix burner design). With the significantly higher flame temperatures, a greater amount of NO_x might be expected for PDF. One possible influence countering that of temperature is the more stable PDF flame which can lead to reduced NO_x production.

The data for PDF from the ENCOAL plant are shown in Table 3.

	<u>Buckskin</u>	<u>PRB1</u>	<u>PRB2</u>
PRB, Unblended		758	
PDF (from ENCOAL) Unblended	750		
Blended with 25% PDF			808
Blended with 20% E1	564	696	676
Blended with 20% E2	686	612	678

Table 3. Average NO_x Levels (ppm), Taken from Same 1 Hour Period as Furnace Pressure Data in Figure 7 and 8.

NO_x values are essentially the same for unblended PDF from the ENCOAL plant and unblended run-of-mine PRB coal in these tests. Thus, at least for these conditions, the significantly higher flame temperature does not produce a correspondingly higher level of NO_x. It does appear that the addition of 20% Eastern coal depresses NO_x somewhat. Optimizing burner conditions for minimal NO_x can have a significant impact on these relative values.

FUTURE WORK

The next step in the project is to get the plant re-commissioned and back on line upon completion of the latest modifications. Then the new finishing and stabilization equipment can be tested. Assuming the new equipment works well, steady state operation of the entire integrated plant should then commence. It will take at least two months of steady operation to generate enough PDF for the first test burn, anticipated to be with Wisconsin Power and Light.

Automatic start-up and shut-down should be achievable in the coming year. Early in the year, ENCOAL expects to evaluate the capacity of the new finishing and stabilization equipment and determine if a plant emissions test can take place. It is also anticipated to test at least one alternate coal during 1994.

In the long run, the goal is to achieve 90% availability of the plant, complete the plant testing program and move on to steady state production of PDF and CDL at plant capacity. The plant should continue to generate data for the design of commercial plants. It should also provide the product and information to evaluate the opportunity for upgrading of the CDL for chemical recovery or transportation fuels. Upgrading of the PDF or some of it is not out of the question either, since anode grade carbon and activated carbon markets are expected to grow.

CONCLUSIONS

The ENCOAL Project continues to progress toward its goals. The debugging phase is nearing completion and steady state operation is anticipated in the near future. Combustion testing on the solid product indicates it will burn in a stable, smooth, and environmentally acceptable manner. Plant availability is improving and it can be operated safely.

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GLOSSARY

ASTM	American Society of Testing Methods
API	Air Position Indicator
BACT	Best Available Control Technology
Bbls.	Barrels
Btu	British Thermal Unit
CDL	Coal Derived Liquid
CO	Carbon Monoxide
DOE	U. S. Department of Energy
ENCOAL	ENCOAL Corporation
EPA	Environmental Protection Agency
ESP	Electrostatic Precipitators
H ₂ O	Water
HazOps	Hazards of Operations
HHV	Higher Heating Value
lb.	Pound
LFC	Liquid From Coal
MK	Dust Control Additive
MMBTU	Million British Thermal Units
N/A	Not Available
NO _x	Nitrogen Oxides
OSHA	Occupational Safety & Health Administration
PDF	Process Derived Fuel
PLC	Programmable Logic Controller
PPM	Parts Per Million
PRB	Powder River Basin
ROM	Run-of-Mine
S-Belt	Vertical conveyor with flexible sidewalls and rubber buckets
SGI	SGI International
SMC	SMC Mining Company
SO ₂	Sulfur Dioxide
Std. Dev.	Standard Deviation
TEK-KOL	Partnership between SGI International and SMC Mining Company
vs.	Versus
WP&L	Wisconsin Power and Light
wt.	Weight
#	Pound

THE COAL QUALITY EXPERT: A FOCUS ON SLAGGING AND FOULING

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INTRODUCTION

No one would disagree that coal quality can affect the performance, reliability and economics of a coal fired power plant. From the very moment coal enters the premises of the power plant, coal quality begins to affect power plant operation. Variations in coal properties can affect everything from coal transport and storage to pulverization, combustion and emissions. Depending on the particular problem or focus at a power plant, attention might be preferentially given to a specific coal property, the coal's sulfur content, as an example. The use of low sulfur Western coals in units designed for Eastern bituminous coals is one common example of one approach for meeting SO₂ emissions. And while SO₂ would, indeed, be decreased there could be other problems ranging from inadequate pulverizer capacity to increased fouling in the convective passes of the boiler to decreased collection efficiency in the electrostatic precipitator. An accurate assessment of the impacts

of coal quality must necessarily include all the impacts that a change in coal quality might have, over and above the one that might be the primary focus.

Under Round 1 of the U.S. Clean Coal Technology Program, the Department of Energy (DOE) and the Electric Power Research Institute (EPRI) made a decision to sponsor the development and demonstration of a powerful computer program called the Coal Quality Expert (CQE™).

What is the Coal Quality Expert? The CQE is a comprehensive, PC-based program that can be used to evaluate various potential coal cleaning, blending and switching options to reduce power plant emissions while minimizing generation costs. It is comprised of over 20 submodels (Figure 1) which are designed to predict all the impacts of coal quality on power plant operations, maintenance, economics and emissions. The design philosophy of the CQE and descriptions of the various submodels have been described in detail in previous papers [1, 2].

Arguably, the most difficult of all coal properties to accurately predict has been the behavior of the mineral matter during the combustion process, i.e., the formation of ash deposits, usually termed slagging and/or fouling, depending on their location in the boiler. The CQE contains an advanced methodology for predicting the formation of and the impacts from ash deposits which are generated under conditions resulting from the combustion of a particular coal.

Because of its' broad based , comprehensive nature, the CQE must be able to handle detailed calculations as well as a voluminous amount of data during its execution. An object based technology was chosen as being best suited to meet the needs of this program. Significantly, an accurate prediction of slagging and fouling must necessarily integrate the operating conditions of the boiler into the solution. Simply stated, the characteristics of ash deposits will be significantly affected by boiler operating conditions, and conversely, the impact of ash deposits will influence boiler operating conditions. Gas temperatures, for example, have a significant impact on the characteristics of ash deposits; gas temperatures

will in turn be affected by "boundary conditions", such as the thermal resistance offered by ash deposits. It becomes apparent that an accurate prediction of ash deposit impacts will require computational interaction between boiler operating conditions (gas temperature) and the thermal resistance offered by the deposits. Since the CQE also contains a boiler performance model which computes, among other things, gas temperatures, it has the capability for achieving heat balance closure with regard to gas temperatures and deposit thermal resistance.

ASH DEPOSITION IN PULVERIZED COAL FIRED BOILERS

Overview of the Ash Deposition Process

The process of ash deposition in pulverized coal fired boilers is extremely complex and involves numerous aspects of coal combustion, mineral matter transformation and chemical reactions within deposits. The following can all play a role in the formation of ash and the ash deposition process:

- Coal organic properties
- Coal mineral matter properties
- Combustion kinetics
- Vaporization/condensation of ash species
- Mineral transformation and decomposition
- Fluid dynamics
- Ash transport phenomena
- Deposit chemistry: specie migration and reactions
- Heat transfer to and from the deposit

Moreover, the above phenomena are usually inter-related and generally strongly influenced by firing system and furnace design. The importance of furnace operating conditions on the combined results of each of the above can also spell the difference between a problem situation and one where no problem exists.

Because of the complexity of the ash deposition process it is difficult to reduce it to a few,

dominant terms that might be reliably described and predicted by relatively simple bench scale tests. Indeed, the inability of routine bench scale analyses to reliably predict fireside performance has continued to motivate researchers to find more reliable solutions.

Impacts of Ash Deposits

The presence of ash deposits can cause the following problems in a coal fired boiler:

- Reduced heat transfer
- Impeded gas flow/increased pressure drop
- Physical damage to pressure parts (slag drops)
- Removal of bottom ash

The short term consequences of the above problems can result in the following:

- Excessive furnace outlet temperature
- Excessive attemperator spray
- Excessive tube temperatures
- Bridging of bottom ash hopper

Problems like the above can result in reduced generating capacity, unscheduled outages, reduced availability, lower plant efficiencies, higher maintenance costs and expensive modifications.

Ash deposits are often categorized relative to their location in the boiler and sometimes to the nature of the deposit. Slagging is the term used to describe ash deposition on heat transfer sections in the radiant sections of the furnace, deposits here frequently have a molten or semi-molten appearance. Fouling typically refers to ash deposition in the convective passes of the boiler; deposits in this region are generally sintered, but can be molten in more extreme cases.

The most important manifestation of an ash deposit is its' effect on heat transfer. Heat transfer can be impeded by a combination of radiant effects and conductive effects.

Changes in radiant heat transfer (absorptivities/emissivities) can occur relatively quickly since it is a surface phenomena; changes in thermal conductance will necessarily occur over a longer timeframe since deposit thickness will change with time. The Physical state of the deposit can also have a significant effect on the radiative properties; molten deposits, for example will result in higher emissivities/absorptivities than sintered or powdery deposits. Although thin, molten deposits are less troublesome from the standpoint of heat transfer than thick, sintered deposits, the former are much more difficult to remove and can eventually result in frozen deposits near the bottom hopper which can cause bridging in extreme cases.

Impeded gas flow can occur as the result of significant deposition on heat transfer surfaces in the convective passes. In addition to an increased pressure drop, ash deposition will change heat transfer, frequently referred to as a surface effectiveness factor. In the extreme, deposits can grow to the point where they cause bridging between the tubes in which case the free area is decreased and local gas velocities can become quite high.

Physical damage to pressure parts can occur when large deposits accumulate in the upper furnace and become dislodged or are blown off the soot blowers and proceed to fall onto the slopes of the bottom hopper where they can cause pressure part damage. Deposits of this type are usually characterized by their relatively high bonding strengths and their highly sintered structure which permits large deposits to form before becoming dislodged.

Historical Methods for Predicting Ash Deposit Effects

Bench scale techniques, notably ASTM tests, have been the most commonly used measurements for predicting ash behavior in a boiler. There have also been ASTM-derived indices such as base/acid and iron/calcium ratios. Specialty tests have been devised in the hopes of providing better predictive tools.

Pilot scale testing can provide results with much higher confidence levels than the traditional bench scale results, but at a price which is considerably higher than bench scale analysis.

Finally there is the option of full scale field tests. The results from such testing, of course, represents the "prime" standard, but usually at a price that far exceeds pilot scale testing. Unlike the bench scale tests, pilot scale and full scale testing have the advantage of being able to quantify the results as a function of boiler operating conditions. As previously noted the behavior of a particular coal is dependent on its' own properties as well as the conditions under which it is being fired.

Computational models have the ability to factor in both fuel properties as well as boiler operating conditions to provide an interactive analysis of ash deposit effects at reasonable cost. The difficulty for many computational models which try to predict slagging/fouling effects is the ability to provide a fundamentally sound, interactive model which has been formulated with and validated by bench, pilot, and field experimental results.

Overview to Predicting Slagging/Fouling in CQE

The goal under the CQE Program was to develop a fundamental, interactive, PC-compatible model for the prediction of slagging and fouling in a pulverized coal fired boiler. Specific objectives for the slagging/fouling model were to quantitatively determine:

- An operational limit beyond which continuous operation is not possible.
- Thermal resistance to heat transfer caused by deposits
- Frequency of sootblowing required to maintain acceptable boiler operation.
- Effect of boiler load decreases on slag shedding and cleanability.

EPRI's Coal Quality Impact Model (CQIM) has served as the foundation for CQE. One of the areas within the CQIM that was identified as a candidate for enhancement was the slagging and fouling submodel. In the CQIM, coal ash deposition impacts were based on a number of conventional indices, most of them being derivatives of ASTM analyses, which implicitly assume that coal ash is a homogeneous substance. Such an assumption is insensitive to the knowledge that individual fly ash particles have different compositions and therefore capacities for different behavior; for example, some particles might exhibit a high degree of stickiness because of their relatively low melting temperatures while others may

have high melting temperatures and not exhibit any stickiness. In formulating an improved slagging/fouling predictive methodology under CQE, the following questions were asked:

- What minerals are present in the coal?
- How is the inorganic material associated with the organic fraction of the coal?
- What is the mineral size distribution?
- How do mineral interactions affect ash particle formation?
- Which ash particles initiate deposition?
- How does ash deposit strength change with time?

These issues cannot be addressed solely by the use of conventional analytical procedures which are based on bulk properties of the coal and ash; bulk properties cannot accurately represent the behavior of individual coal and ash particles in the boiler. Computer Controlled Scanning Electron Microscopy (CCSEM) represents an advanced analytical technique that allows an individual-particle-based approach to be used in the CQE advanced methodology.

PSI PowerServe (formerly PSI Technologies) and the University of North Dakota, Energy and Environmental Research Center (UNDEERC) were subcontracted by ABB Combustion Engineering to develop algorithms for predicting the effects of slagging and fouling, respectively. Both organizations had been involved in previous studies where they were developing models to predict fly ash formation and to characterize deposition processes. Figure 2 represents the key processes leading to ash deposition.

The foundation for accurate prediction of ash deposition effects is an accurate prediction of the fly ash size and composition. Each fly ash particle will behave in accordance with its' individual properties, size and composition being the two key factors. The size of the particle will largely dictate how it behaves in a particular flow field, i. e. whether or not it will impact a heat transfer surface. The composition will largely determine if the particle will stick once it has impacted the surface. Scanning electron microscopy (SEM) has provided the analytical means by which coal mineral matter can be evaluated; it has allowed

a far more accurate prediction of fly ash particle size and composition than more conventional, ASTM-based analysis alone. It should be noted, however, that CQE will be operative if only ASTM results are available; surrogate SEM data can be internally chosen based on the ASTM data through a submodel Scanning Electron Microscopy Interpolation Algorithm (SENINAL), though it is preferable to have the specific SEM information.

Transport phenomena are described to determine the flight of fly ash particles and their interaction with heat transfer surfaces. Particle deposition is then described; various processes constitute the overall deposition process, as shown in Figure 2.

The boiler has been divided into specific regions, some of which are best described by slagging phenomena, addressed by PSI PowerServe, and other regions that are best described by fouling phenomena, addressed by UNDEERC. Figure 3 depicts the various regions of the boiler as; PSI PowerServe has addressed regions 1 through 5 and UNDEERC has addressed regions 6 through 10.

SLAGGING MODEL (SLAGGO)

Slagging Prediction Approach

PSI PowerServe has combined the bench, pilot scale and field testing in the CQE program, in concert with their previous experience, to improve the prediction of utility furnace slagging. This improvement, termed SLAGGO, is comprised of a combination of previous models and new models which have been based on the experimental results of the CQE program. This approach has allowed the establishment of links among coal (and ash) properties, furnace design, and operating conditions.

The indices created by SLAGGO are relative indices to be compared to a baseline (reference) case for each boiler. The baseline case will ideally include a coal and a set of operating conditions for which the boiler performance is known in detail. Once the baseline case is established, the predicted performance for a new candidate coal can be comparatively evaluated. If the predicted performance is unacceptable, a number of parameters can be changed in the model to determine the best combination of fuel and

operating conditions, in terms of the slagging performance, including:

- Fuel properties
- Excess air
- Maximum continuous boiler rating
- Sootblower frequency and location
- Time at maximum continuous rating (or time before a load drop is required)

The CQE boiler performance model will then be used to evaluate the effect of the above changes on overall boiler performance and economics. Operating conditions will likely be chosen by the plant manager based on the predicted economic and operating impacts. In this manner the plant operator or manager can assess which operational changes are best, given his constraints.

As the number of coals, boiler designs, and operating conditions that are utilized by any user increase, the confidence level in the predictions will increase. This confidence factor is not just familiarity with the software, but also experience in terms of the predictions and the correlation of the predictions while varying parameters at a particular unit. SLAGGO is designed for the prediction of the behavior in all major furnace configurations.

Description of Submodels

SLAGGO has several components to simulate the entire cycle of ash formation, deposit initiation, growth, and removal processes. An overall schematic of the process is shown in Figure 4. The overall model is comprised of a number of submodels to describe the formation and deposition of fly ash:

- Ash Formation Model (AFM)
- Ash Transport Model (ATM)
- Deposit Growth Model (DGM)
- Thermal Properties Model (TPM)
- Deposit Removal Model (DRM)

The ash formation model (AFM) starts with the coal CCSEM data and calculates the fly ash particle size and composition distribution (PSCD). Each of the submodels has a number of components, but the AFM is the most complicated with several elements:

- Mineral Matter Transformation code (MMT)
- A preprocessor that renders MMT applicable to cyclone combustors
- Alkali Vaporization Model (ALKAVAP)
- Excluded pyrite kinetics model (PYRKIN)

Mineral Matter Transformation

The driver for the SLAGGO model is the MMT model which is a fundamentally-based model initially developed under DOE AR&TD funding. MMT takes as input the mineral analysis data for a given coal, follows the transformation process of coal mineral matter during combustion, and produces as output the fly ash particle size and composition data required for the prediction of slagging. ALKAVAP uses the ASTM ash analysis data, the temperature and the oxygen concentration in the burner zone, and calculates the vaporized fractions of alkali (sodium and potassium) and alkaline earth (calcium) metals as oxides. The inputs for PYRKIN are the size distribution of the excluded pyrites as produced from MMT and the temperature and the oxygen concentration in the burner zone; the output is the time for a melt phase to appear in an excluded pyrite particle of a given size and the time for the melt phase to disappear due to iron oxide crystallization. These times are reported for all the excluded particles in the size distribution, and are used by the DGM.

Ash Transport Model

The ash transport model (ATM) calculates the ash flux transported to the waterwall surfaces by turbulent diffusion. The ATM accounts for aerodynamics in wall-fired, T-fired, and cyclone furnaces. With respect to slagging, there are two regions with differing transport mechanisms. These regions are (1) the radiant region bounded by the walls of the furnace, and (2) the superheater tubes. The radiant region may be further subdivided into zones, for example burner, lower furnace, and upper furnace. The main transport mechanism for ash particles to the wall in the radiant zone is by turbulent diffusion; the main mechanism

for the superheater tubes is inertial impaction.

Deposit Growth Model

The deposit growth model (DGM) simulates three main sequential events: (1) deposit initiation by small ash particles arriving by turbulent diffusion and adhering by van der Waals force; (2) deposit growth by sticky ash particles impacting on the existing ash deposits; and (3) deposit maturation.

The stickiness of ash particles arriving at waterwalls is determined by the viscosity model previously developed by PowerServe. The viscosity model predicts particle viscosity at a given temperature from the composition of the individual ash particles. The strength of a deposit at a given time is determined from the density of the deposit which is calculated by the sintering rate of spherical ash particles. The primary goal of the DGM is to predict the change in the cleanliness factor with time in six different regions of a furnace.

The cleanliness factor is defined as the ratio of the heat transmitted across the waterwall tubes with deposit on them to the heat transmitted across the "clean" waterwall tubes; "clean" refers to the state of cleanliness after effective commercial sootblowing. The cleanliness factor decreases with time until it reaches an equilibrium value and reflects the effect of slagging on boiler thermal performance. The cleanliness factor can be used to estimate the optimal sootblowing frequencies for economical operation. Since the DGM keeps track of the porosity change of the initial layer, it also forms the basis for computing deposit strength and it relates deposit strength to deposit removability by sootblowing.

Thermal Properties Model

The DGM requires knowledge of the thermal properties of the ash deposit, such as thermal conductivities and emissivities, under different deposit conditions. The thermal properties model (TPM) calculates these thermal properties. The emissivity and thermal conductivity of an ash deposit are functions of temperature, porosity (sintering), and chemical composition; the model calculates thermal conductivity and emissivity using data from models described above.

Deposit Removal Model

The deposit removal model (DRM) simulates deposit removal by sootblowers. Sootblower efficiency is initially determined from the performance data provided by users for the baseline coals. The sootblower characterization curve, thus determined, and the deposit strength from the DGM, are used in concert to predict deposit removability. Change in the cleanliness factor following sootblowing is determined as the final output.

SLAGGO Inputs and Outputs

The exact nature of the input and output screens for SLAGGO is still being formulated. Additionally, default values will be provided for virtually all input information. Although use of the default values is discouraged, the program will operate without most inputs. The input information will be organized into three main topics: coal properties, boiler design, and boiler operation parameters as follows.

Coal Properties

- Coal name and rank
- Ultimate and Proximate analysis
- ASTM ash analysis
- CCSEM data
- Coal Particle Size Distribution (PSD) data

Boiler Design

- Boiler name
- Boiler type
- Boiler dimensions (so that a cross sectional area can be calculated)
- Air and fuel injection information
- The number of sootblowers in each furnace zone (1 through 5)
- Type of sootblowers - air, steam, or waterlance.
- Single wall fired

- Opposed wall fired
- Tangentially fired
- Cyclone fired

Boiler Operation

- Load level
- Load mode of operation
- Air feed rate and distribution
- Fuel feed rate and distribution
- Furnace exit gas temperature
- Maximum time at full load
- The frequency of sootblower use by furnace section

Additionally, options will be provided for low NO_x firing systems and for the corresponding variation in slagging behavior as a function of furnace location.

In SLAGGO a particular boiler load will be specified as an input. If there is a slag-related problem at full boiler load, then the user can specify a reduced load as one means to address a slagging problem, i.e., slag shedding. The use of reduced load to control slagging is handled by a prediction of the maximum time at full load. The program predicts the continual deterioration of conditions that occurs in cases where load drop is necessary, and a prediction is made for the time it takes to reach the minimum cleanliness factor level; this time defines the maximum time at full load.

Output Information - The key output will be a cleanliness factor diagram as a function of furnace location (see Figure 5). This diagram will be compared to diagrams from other cases, including the base case, so that a decision can be made regarding the choice of fuel and operating condition.

The cleanliness factor diagram is illustrated in Figure 5 shows two modes of behavior. In

both cases, the beginning of the graph represents a time when the furnace has been thoroughly cleaned. The "stable case" represents a situation where sootblowing can adequately remove deposits and the minimum cleanliness factor does not change significantly. In this case, the local cleanliness factor drops until sootblowing occurs which causes an immediate recovery. The degrading case represents a situation where sootblowing is inadequate, and the cleanliness factor continually drops until a critical condition is reached. At this point the utility must respond with a change in operating conditions to prevent severe slagging. By using the cleanliness factor diagram in this manner, the following, targeted slagging areas of concern can be addressed:

- The furnace operational limits
- The required sootblower frequency
- The effect of load drop
- The effect on thermal resistance caused by slagging

Many different cleanliness factor behaviors are possible, depending on the input conditions, and the furnace location being considered. Under some conditions, the cleanliness factor will not decrease significantly, corresponding to very low slag buildup. Under other conditions, the cleanliness factor decrease will be more rapid and the recovery due to sootblowing lower. In some furnace locations, no sootblowers exist; therefore, there will be no recovery. The cleanliness factor can be evaluated (compared) as a function of different coals and/or changes in input conditions to obtain acceptable slagging conditions.

In addition to the cleanliness diagrams, the output of a wide variety of more detailed information is possible. The exact level of detail available in the final version of CQE is presently being discussed, but the data attainable include:

- Coal mineral particle composition and particle size distributions
- Fly ash composition and particle size distributions
- The slag layer composition, thickness, porosity and sintering rate as a function of time and location

The slag emissivity and thermal conductivity as a function of time and location

Code Operation and Interfacing

SLAGGO utilizes the above mentioned algorithms to predict ash deposition in the radiative section of the utility boiler. The lower and upper sections of the furnace are divided into several zones: one zone for the ash hopper region, a zone for each burner level, two zones between the top burner and the nose, and two zones for the upper furnace, if no tube banks are present, from the nose to the roof. Boiler operational conditions and dimensions for each zone and the fly ash particle size and composition distributions are received as input from the boiler model and user input.

The code is set up so that a sequence of procedures is implemented for each of the zones described above as follows:

- The initial deposit layer is calculated from the amount of ash particles which stick to the bare metal heat transfer surfaces.
- After the initial deposit layer reaches a thickness of 100 microns, the bulk layer ash deposition rate is calculated.
- The thickness of the ash deposit layer increases until the deposit surface exceeds the temperature at which the deposit is assumed to be running slag.
- The amount of deposit removed by sootblowing is calculated from the strength of the existing deposit and a sootblowing calibration curve which is generated from full-scale data entered in by the user of the program.
- Thermal properties of the deposit are calculated for all the zones based on sintered state, thickness and radiative properties.

Fly ash particle size and composition distributions for the SLAGGO code are predicted from the initial coal properties as measured by ASTM analysis or preferably CCSEM analysis, or as measured directly from an entrained ash sample should one be available. The CQE code utilizes the mineral matter transformation (MMT) code to predict the particle size and composition distribution (PSCD) of the entrained ash as a function of the

original coal properties. The PSCD of the ash is divided into vapor species, pyritic species and residual ash. The residual ash is divided into 512 bins based on calculated ash viscosity.

Experimental Data Input/Validation

The coding of \$LAGGO and integration with CQE is currently being finalized. Validation of the entire model will occur in the near future. However, the DGM and the TPM have been verified using data provided by the ABB Combustion Engineering Fireside Performance Test Facility using two HVA Bituminous coals.

A detailed description of the FPTF can be found elsewhere [3]. In brief, the FPTF is an up-fired furnace with a firing rate of 3 to 4 MBtu/hr. Permanent panels are used to study the heat transfer reduction as slag builds up. Single-use, sacrificial ash deposition probes were also used to collect slag deposits for in-depth analysis. In order to obtain a general understanding of the deposition characteristics of the two coals, the deposits were cross-sectioned along the direction of the deposit growth and were examined under CCSEM. The changes of the chemical composition and porosity along the deposit growth direction were examined. Additionally, the heat flux across the wall panel was monitored continuously throughout the test run by measuring the heat absorption with a cooling fluid.

Simulation of the ash deposition process for a hvA bituminous coal was carried out with a simplified version of the SLAGGO algorithm; only the deposit growth portion of the code was considered. Figure 6 shows the calculated $q_{dirty}/q_{initial}$ compared against the measured values for this coal. The measured q_d/q_i rapidly decreased in the first 2 hours and then leveled off approaching the equilibrium value after 12 hours. The trend of the change of the thermal degradation with time suggests that the effective thermal conductivity of the ash deposit formed in the first 2 hours is lower than that formed over the 12 hour period. The effective thermal conductivity increases with increased sintering of the deposit, and will result in a flattening of the curve; this shows more clearly the effect of the deposit sintering on the thermal degradation. The heat flux ratio, q_d/q_i , for the first 2 hours shows a better

agreement with the thermal conductivity of 0.2 W/m C, whereas that for the last 4 hours shows a better agreement with the thermal conductivity of 0.8 W/m C. In this initial version of the DGM, a constant value for the thermal conductivity was used. In the final version the thermal conductivity will vary with porosity as the deposit matures.

Figure 7 shows the deposit composition profiles for the same two hvA bituminous coal. Comparison of the calculated with the measured composition profiles shows good agreement. The composition change with deposit thickness is minimal indicating that most of the ash particles are sticky at the temperature at which the testing was performed.

FOULING MODEL (FOULER)

Fouling Prediction Approach

Fouling refers to the deposition of ash in the convective pass region of a utility boiler. Deposit characteristics throughout the convective pass can change dramatically in morphology, varying from strong, highly molten deposits to weak, powdery deposits. The prediction of fouling and its effects on heat transfer is a complex process that requires information about the coal properties and operational parameters. Fouler, is a code developed by the Energy and Environmental Research Center, EERC, to predict the convective pass fouling of a coal-fired facility.

The fouler code receives the required input information from the CQE heat transfer module, interface shell, and the mineral matter transformation (MMT) code as mentioned in the previous section. The heat transfer module supplies the temperature and fluid flow properties of the system prior to deposition. The interface shell supplies the operational parameters such as sootblower configurations and mass loadings as entered by the user. The MMT algorithm supplies the necessary ash particle size and composition information.

In general, fouling deposit formation can be described as two interacting mechanisms: deposit growth and strength development. As the deposit grows, the temperature profile throughout the deposit changes, which affects the strength development and future deposit growth. The deposit growth is influenced by both transport to the heat-exchange surface

and adhesion to the surface. The effects of deposit growth and strength development can then be applied to the thermal properties of the deposit and the deposit removability.

Description of Submodels

Fouler is comprised of over 25 different subroutines which can be grouped together as four general algorithms: (1) Deposit Growth, (2) Strength Development, (3) Thermal Properties, and (4) Deposit Removability.

Deposit Growth

The three primary methods of deposit growth which are accounted for in the fouling model are: (1) inertial impaction and eddy impaction, (2) vapor-phase and small particle diffusion, and (3) thermophoresis/electrophoresis. The initial upstream layers around a tube are generally deposited by vapor-phase and small particle diffusion and by thermophoretic/electrophoretic forces. The inner layer is composed primarily of condensed vapors and particles less than 5 microns that traverse the boundary layer surrounding the tube and deposit. The actual particles that deposit are dependent upon the flow characteristics around the heat-exchange tubes. At higher temperatures, which result in faster gas velocities, the inner layer is enriched condensed in vapor-phase species and remains loosely bound, while at lower temperatures (and lower velocities) the enrichment tends to shift to particles in the less than five micron range which become sulfated and produce a high strength layer. In both cases, the inner layer serves as the foundation for the eventual formation of massive upstream deposits.

The massive upstream deposits are primarily formed from inertial impaction into the sintered/molten surface of the deposit. This molten surface is often referred to as a captive surface. The larger particles, (greater than 10 microns), become separated from the gas stream as it flows around the tubes as shown in Figure 8. The particles impact the surface and either stick or deflect off depending upon their stickiness as well as that of the captive surface of the tube. As massive deposits grow, the surface temperature of the deposit increases, developing a highly captive surface which will capture most of the impacting particles. As the deposit grows, it also becomes more aerodynamic thus minimizing the

amount of ash which impacts the surface.

Downstream deposits on the tube are formed by impaction of particles in the recirculation eddies passing around the tubes. As the gas stream passes around the tube, those particles that do not inertially impact (generally less than 10 microns) get caught in the recirculation eddies of the gas stream and are impacted into the downstream side of the tube surface as shown in Figure 9.

Strength Development

As mentioned previously, strength development is generally due to one of two sintering mechanisms: silicate- or sulfate -based. The general temperature of crossover from sulfate- to silicate-based sintering is 1850°F (1000°C) due to the instability of sulfates above that temperature. Silicate-based sintering is attributed to the viscous flow of amorphous material during and after deposition. The low viscosities responsible for silicate-based sintering are commonly attributed to higher temperatures and lower melting point phases such as sodium and potassium aluminosilicates. Some of the low melting phases are formed after deposition because of the interaction of the deposited material and gas phase species.

Sulfate-based sintering is attributed to the filling of deposit pores by the sulfation of the alkali-alkaline earth components in the deposit, primarily calcium, sodium, and potassium. Sulfates are generally unstable and decompose above 1850°F (1000°C), but form rapidly at temperatures slightly below the decomposition temperature. The crossover temperature range from rapid sulfation to decomposition is narrow and can be crossed in some areas of the boiler as a result of load swings.

Thermal Properties and Deposit Removability

The thermal properties of the deposit are primarily dependent upon the thickness, temperature, and physical sintered state of the deposit. Correlations have been developed for lightly sintered and highly sintered deposits as a function of temperature. The sintered state of the deposit can be indirectly estimated from the strength of the deposit. Due to the temperature change and sintered state change, throughout the thickness of a deposit as well

as during its growth, the thermal properties are not constant and require multiple iterations to calculate.

The deposit removability algorithm accounts for thermal shedding, sootblowing and gravity shedding. Thermal shedding occurs when a utility drops load which results in a temperature change in the boiler. The change in temperature causes a difference between the thermal contraction of deposit versus tube which results in a shear fracture in the deposit; this can be correlated to the apparent density of the deposit. The sootblowing process accounts for the shear stress applied to a deposit by a retractable sootblower as a function of the blowing media, pressure, nozzle angle and other parameters. The sootblowing removal efficiency is calculated from the strength of the deposit. Gravity shedding is common in the back pass regions of a utility boiler where strength development is low but deposition is high. This form of deposit removal is correlated to a function of the strength/mass ratio of the deposit.

Fouler Inputs and Outputs

The inputs to the Fouler code are far too numerous to be listed here but they can be generalized into four categories: (1) design parameters, (2) temperature and gas distributions, (3) ash size and composition distributions, and (4) sootblowing and load drop parameters. The primary outputs from the code are thermal resistivity as a function of time for each heat exchanger, and the sootblower effectiveness for each bank of heat exchange tubes. Other outputs such as deposit strength development, deposit growth (mass), and deposit composition can also be outputted if desired.

The thermal resistivity of each heat exchange section is returned to the CQE heat transfer module for calculation of the new temperature profile of the boiler. A cleanliness factor can then be calculated for each heat exchange section from the difference in heat transfer between the dirty and clean state of the tubes. The sootblower effectiveness curve is a prediction of the amount of deposit that will be removed depending on the time interval between sootblowing cycles. This curve will allow the user to better optimize their sootblowing cycles.

Code Operation and Interfacing

The fouling model, Fouler, utilizes the above-mentioned algorithms to predict the heat-transfer effects of a particular coal on the convective pass of a boiler. The convective pass of a boiler is divided into as many as twelve individual heat-exchange sections (within the primary superheater, reheater, economizer) for the fouling predictions. Fouler receives, as input, the boiler operational parameters for each section of tube banks (temperatures, velocities, tube spacings) and a fly ash particle-size and composition distribution. The code then separately executes the following calculations for each section of the convective pass. Particle sizes participating in the upstream, downstream and inner layer deposition for each bank are calculated. An inner layer deposit of approximately 100 microns is assumed as the initial tube cleanliness for the first iteration of the test using a two-hour or smaller time increments, the program calculates the amounts of upstream and downstream deposition. The upstream deposition algorithm first determines an impaction efficiency for a given group of particles from particle size and gas velocity. The sticking efficiency is then calculated to determine if the particle will adhere to the surface of the deposit/tube. The downstream deposition is based on the turbulence of the gas as it passes around a tube.

Both silicate-based and sulfate-based strengths are determined for each of the deposits. The silicate strengths are a function of the viscosity and particle size of the deposited materials and the time duration of deposition. The sulfate strength is a function of composition and time. Sulfation strengths above 1850°F (1000°C) are set to zero, since sulfates are unstable above that temperature. The greatest strength as determined from the two algorithms is chosen as the strength for the deposit at that given time.

The removability and heat-transfer characteristics of the deposit are calculated from the deposit mass and strength. Each of the removability algorithms are applied over their user-entered time increments. After a fraction of the deposit has been removed, the heat-transfer properties of the deposit are calculated for each layer of the deposit using correlations derived from various literature sources. The amount and strength of the deposit remaining is then used as the basis for the calculations during the next two-hour time increment. This process is continued for a specified number of time increments.

The particle size and composition distributions for the Fouler code can be predicted from the initial coal properties or measured, by computer controlled scanning electron microscopy, CCSEM, from entrained ash samples. The CQE code utilizes the mineral matter transformation (MMT) code created by Physical Sciences Incorporated (PSI) to predict the particle-size and composition distribution (PSCD) of the entrained ash as a function of the original coal properties. The PSCD of the ash is divided into six size and seven composition bins for a total of 42 different sets of particle information.

Experimental Data Input/Validation

The prediction of deposit compositions for high and low temperature deposits has been compared to pilot-scale experimental results. Pilot scale upstream deposits were collected on a water cooled sacrificial probes in the ABB-CE Fireside Performance Test Facility (FPTF) firing HVA a bituminous coal. The deposits were collected at a gas temperature of 2320°F (1270°C). The current fouling algorithms are designed to predict the potential for a given particle to impact and deposit on the leading edge of a heat exchange surface in the absence of a captive surface. Since the deposit formed from the HVA coal produced a highly liquid layer after significant deposition the predicted results are only compared to the initial non-liquid layer. Input to the fouling code was generated from the mineral matter transformations (MMT) code as predicted from the initial coal properties. Figure 10 compares the deposit before the captive surface formation, predicted deposit and the initial coal inorganic components. The predicted results compare well with the experimentally measured results with the exception of the calcium content.

Full scale downstream deposits were sampled from Northern States Power Sherco Unit #1 as part of Project Calcium. The feed coal was a Wyoming subbituminous. Input to the Fouler code in this case was generated from analysis of entrained ash sampled from the same location as the deposits. The deposits were collected at a gas temperature of approximately 1800°F (980°C). Figure 11 compares the deposit, predicted deposit, and original coal inorganic components. The predicted values compare well with those measured from the full-scale sampling.

SUMMARY

Coal quality can significantly affect the performance, reliability and economics of a coal fired power plant. Arguably, the most difficult of all coal properties to accurately predict has been the behavior and impact of the mineral matter during the combustion process, specifically the formation of ash deposits, usually termed slagging and fouling.

A key part of this U. S. Clean Coal Technology Program, sponsored by the DOE and EPRI, has been the development of algorithms to predict coal ash slagging and fouling behavior in utility boilers for inclusion in the Coal Quality Expert. SLAGGO and FOULER, developed for predicting slagging and fouling, respectively, have been based on a combination of fundamental information from theory and bench scale laboratory experiments together with results from pilot and full scale test results. The slagging and fouling algorithms represent an advanced methodology which recognizes the importance of boiler operating conditions as well as coal properties for the accurate prediction of coal ash behavior and its impacts on boiler operation. By virtue of being part of the Coal Quality Expert which contains, among other things, a boiler performance model the necessary interaction between boiler operating conditions and ash deposit characteristics will occur. Version 1.0 of the FOULER code has been entered into the CQE program; coding of the slagging algorithm is nearing completion. Validation of certain elements within the algorithms has occurred, but overall validation will be undertaken later this year and early next year.

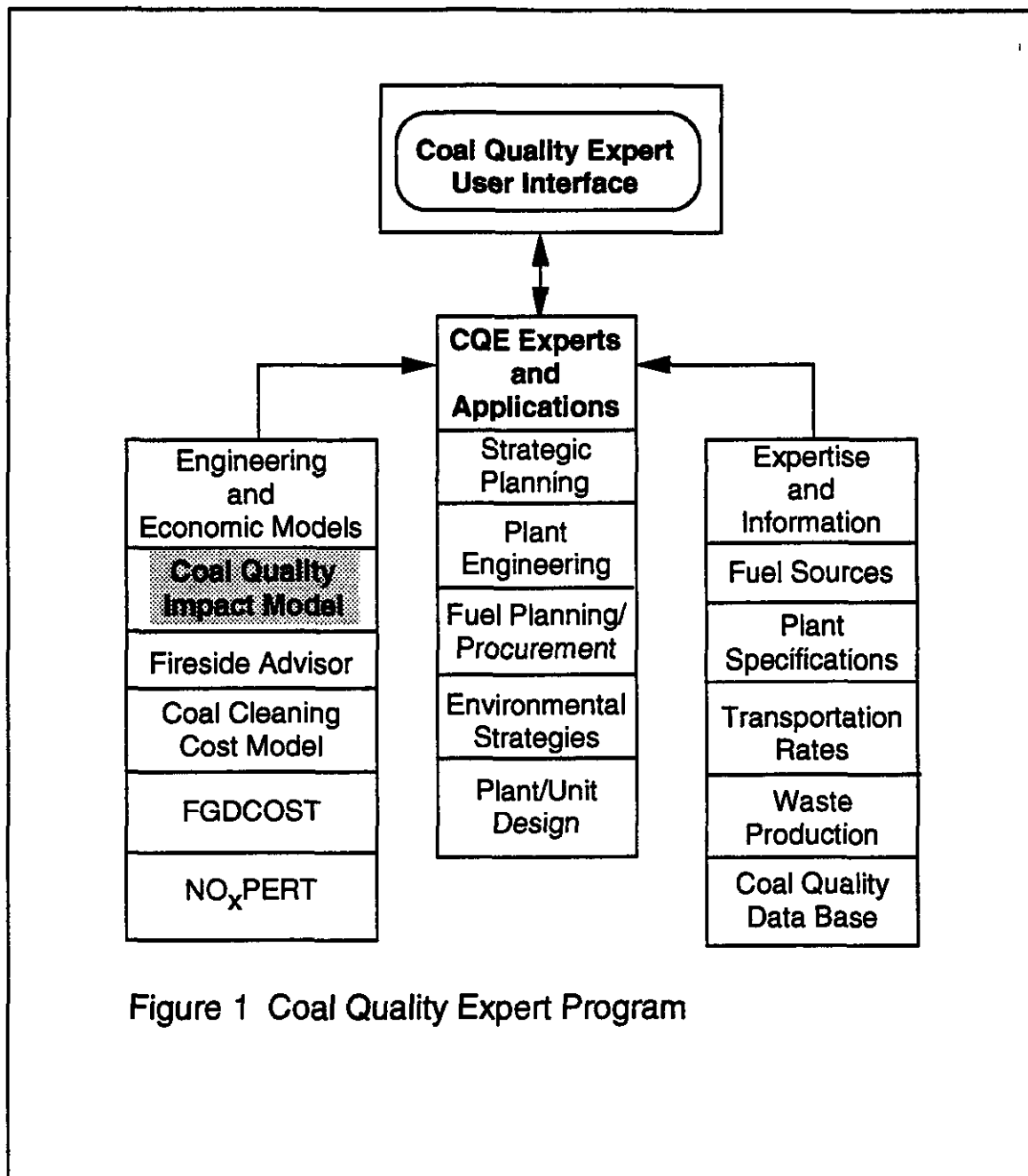
ACKNOWLEDGEMENTS

The authors would like to acknowledge that considerable use has been made of information generated from previous DOE, EPRI and privately funded programs. Specific thanks are due to DOE for supporting the development of the Mineral Matter Transformation model under their PETC AR&TD Program, to EPRI for their support on Combustion Characterization of CCTF coals wherein much of the pilot scale testing methodology was developed and to the sponsors of Project Calcium: Northern States Power, Otter Tail Power, Northern Indiana Public Service, Wisconsin Power and Light, Babcock and Wilcox, DOE and EPRI. On behalf of the entire CQE team the authors would like to acknowledge the

support of DOE and EPRI for the present program and the unique opportunity afforded by the development of the Coal Quality Expert to bring together in a practical way the considerable body of knowledge on coal mineral matter and its effects during combustion.

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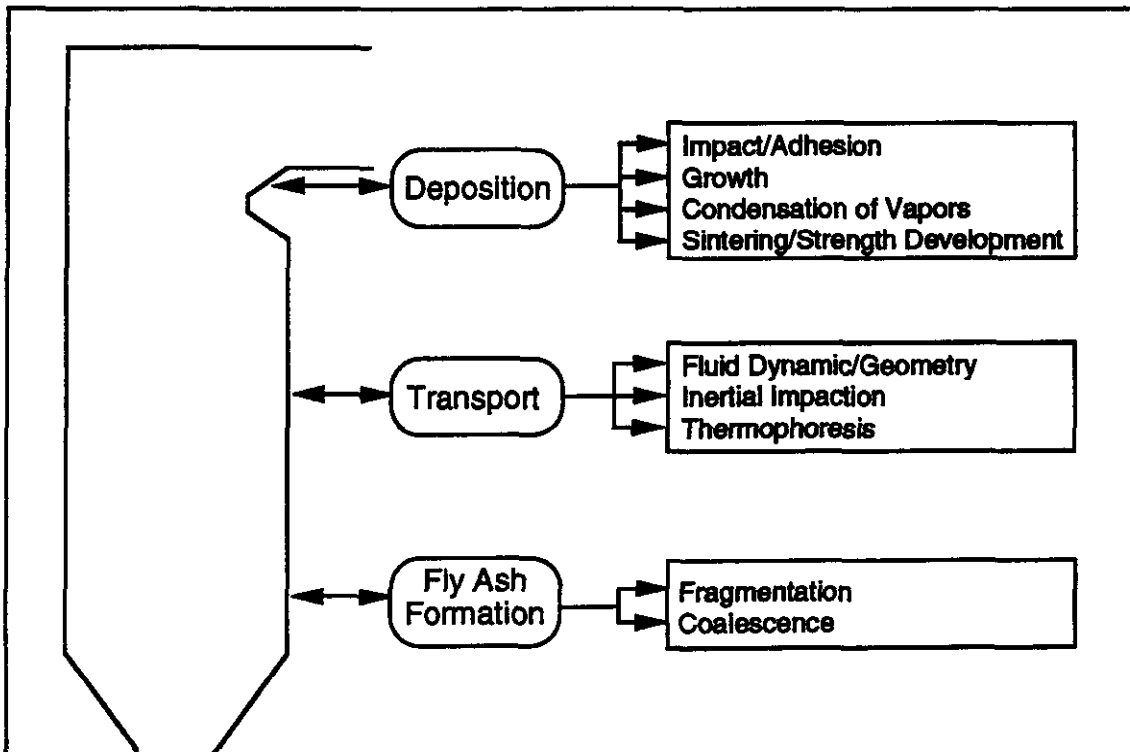
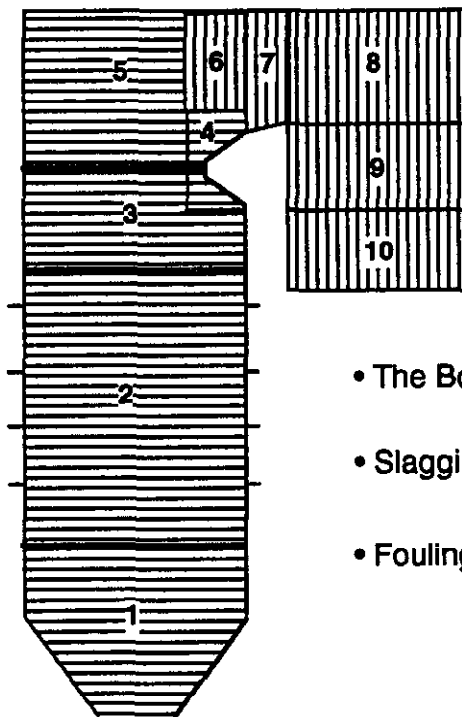


Figure 2 Key Processes Leading to Ash Deposition



- The Boiler is Divided Into Ten Regions
- Slagging Defined as Deposition in Regions 1-5;
- Fouling Defined as Deposition in Regions 6-10;

Figure 3 CQE Defined Boiler Regions for Slagging/Fouling

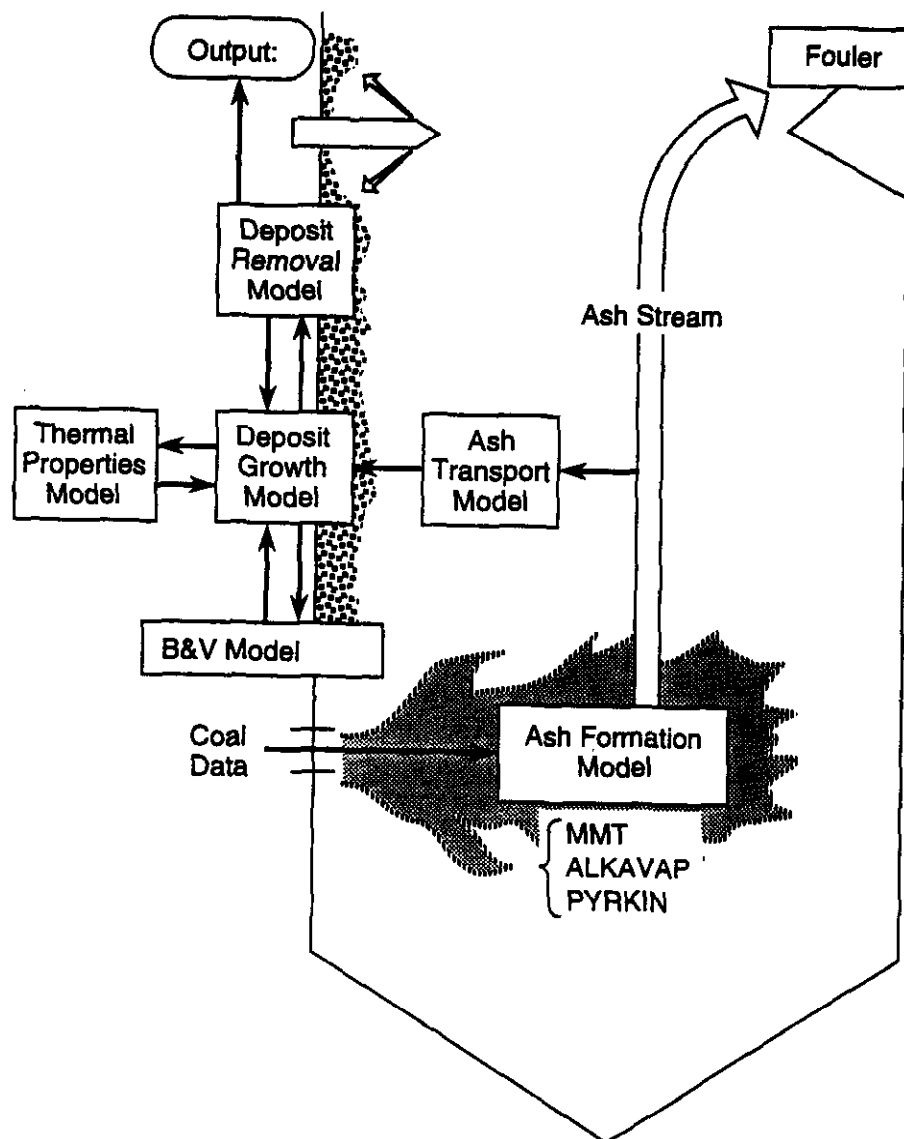


Figure 4 Various Components of SLAGGO

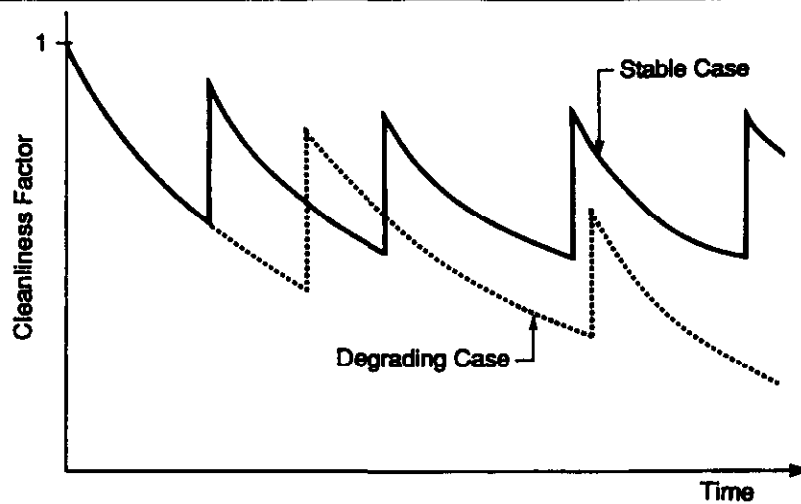


Figure 5 Cleanliness Factor Versus Time Behavior

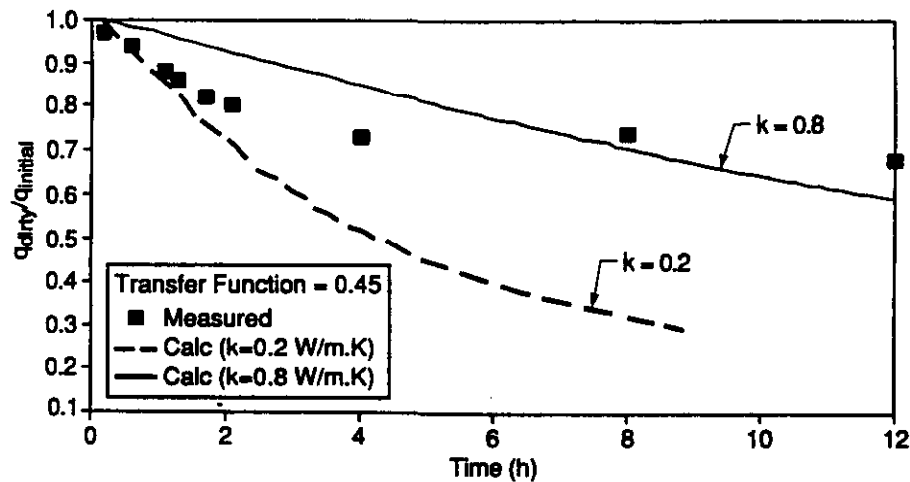


Figure 6 Comparison of Heat Flux Ratios for a hvA bituminous Coal

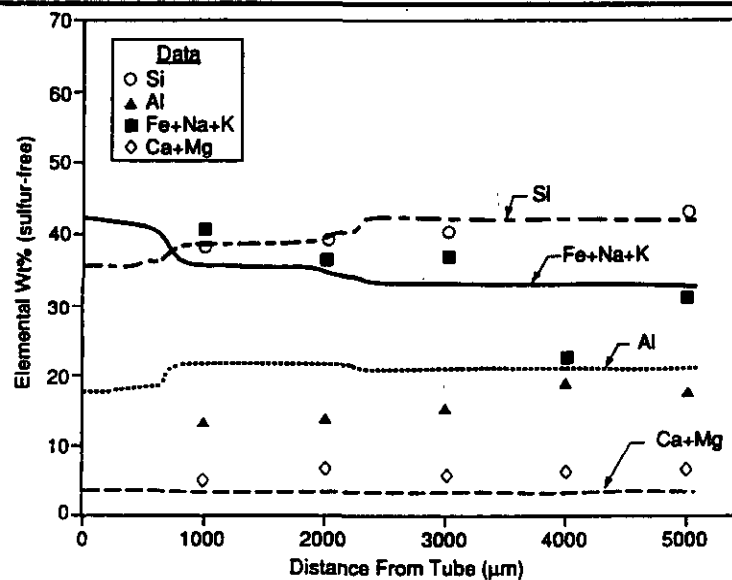
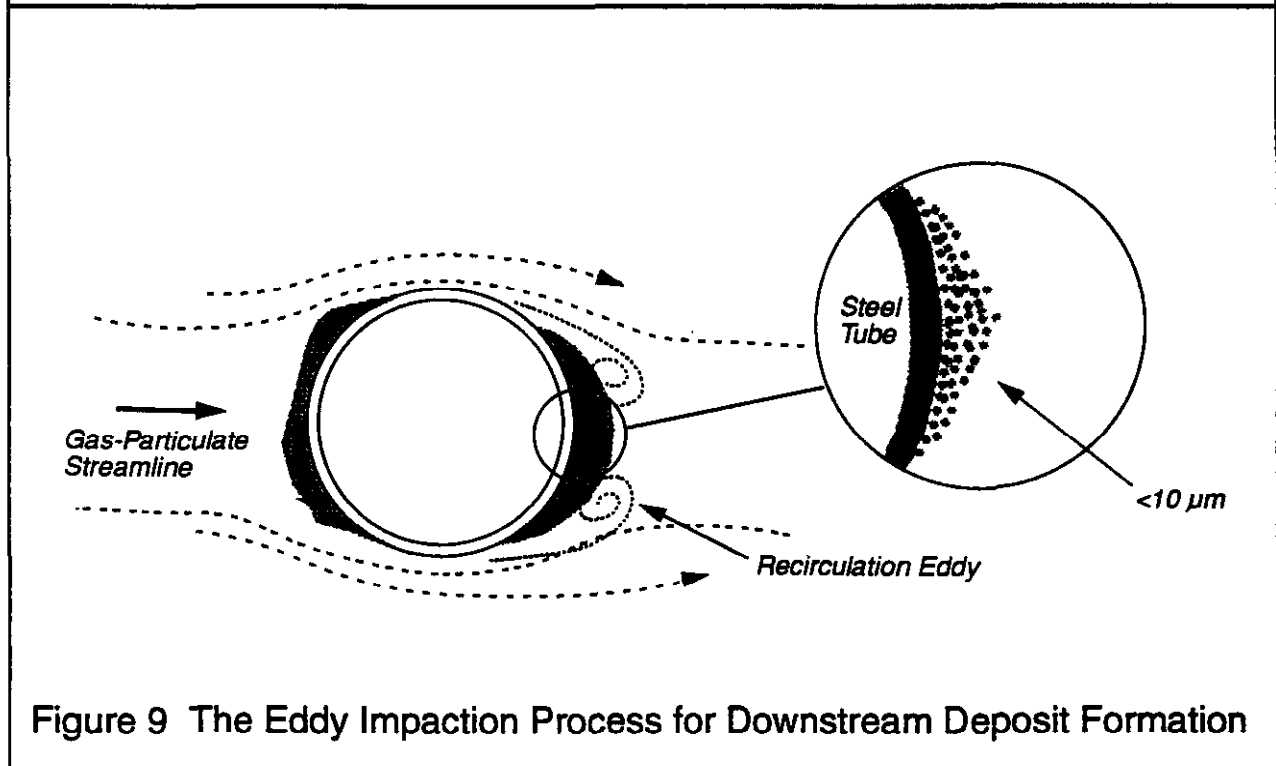
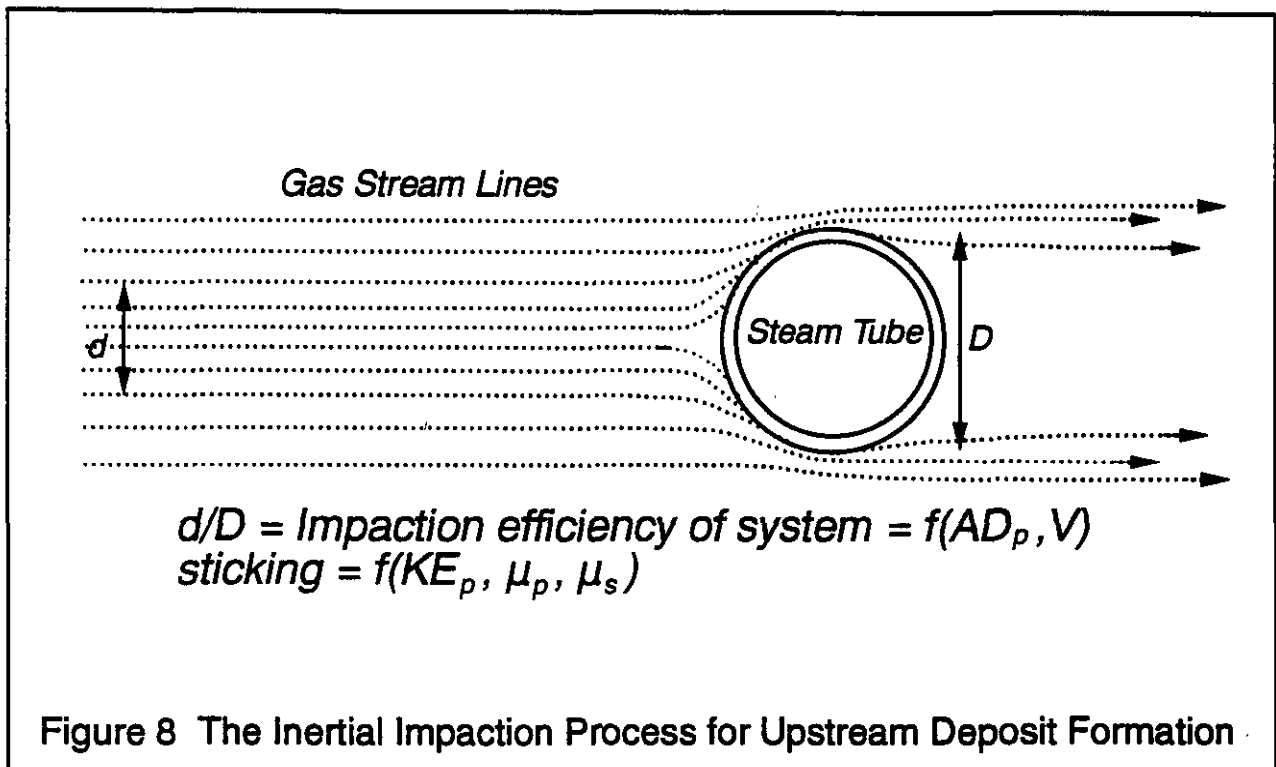


Figure 7 Deposit Composition Profiles for a hvA bituminous Coal



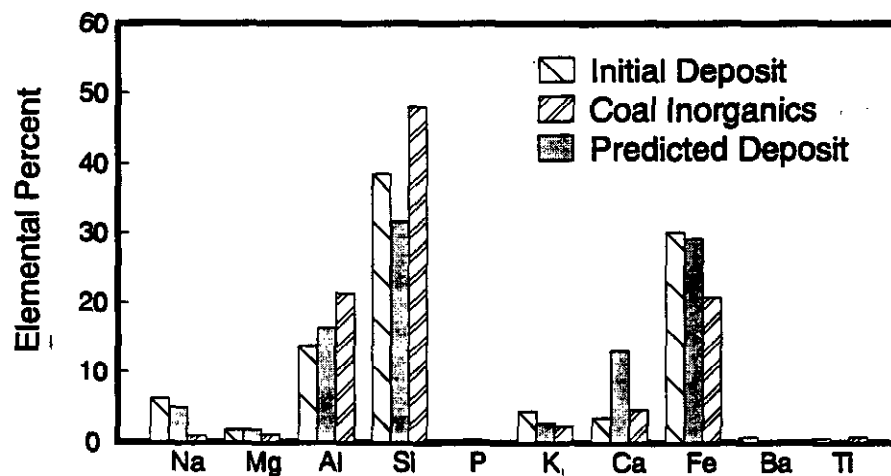


Figure 10 Comparison of Upstream Deposit Components Collected at 2320 °F in ABB-CE's FPTF

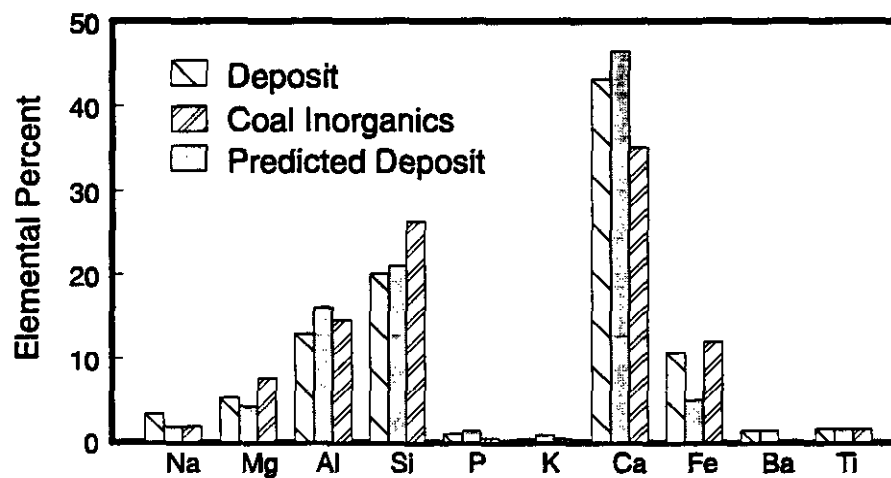


Figure 11 Comparison of Downstream Deposit Component Collected at 1800 °F in Sherco Unit #1

SELF-SCRUBBING COAL: AN INTEGRATED APPROACH TO CLEAN AIR

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ABSTRACT

The Custom Coals advanced coal cleaning plant will be designed with a unique blending of existing and new processes to produce two types of compliance coals: Carefree Coal and Self-Scrubbing Coal. Carefree Coal will be produced by cleaning the coal in a proprietary dense media cyclone circuit utilizing fine magnetite to remove up to 90% of the pyritic sulfur and correspondingly greatly reduce the ash.

While many utilities can achieve full SO₂ reduction compliance with Carefree Coal, others face higher sulfur reduction requirements due to the higher sulfur content of their existing fuel supplies. For these circumstances, a patented Self-Scrubbing Coal will be produced by taking Carefree Coal and pelletizing limestone-based additives with the finest fraction of the clean coal. These technologies will enable over 150 billion tons of non-compliance U.S. coal reserves to meet compliance requirements.

INTRODUCTION

Approximately 65 % of all coal shipped to utilities in 1990 was above 1.2 lbs SO₂/MMBtu. Even though most of that coal has been cleaned in conventional coal preparation plants, it still does not meet the SO₂ emission limitation the Clean Air Act Amendments mandate for the year 2000. Most utilities have announced compliance plans involving either switching to lower sulfur coals from Central Appalachia or the Power River Basin or the installation of scrubbers. Fortunately, for those of us attempting to commercialize clean coal technologies, relatively few long-term decisions have been made in Phase I - i.e. fewer scrubbers are scheduled than initially expected and new coal contracts rarely extend beyond the year 2000.

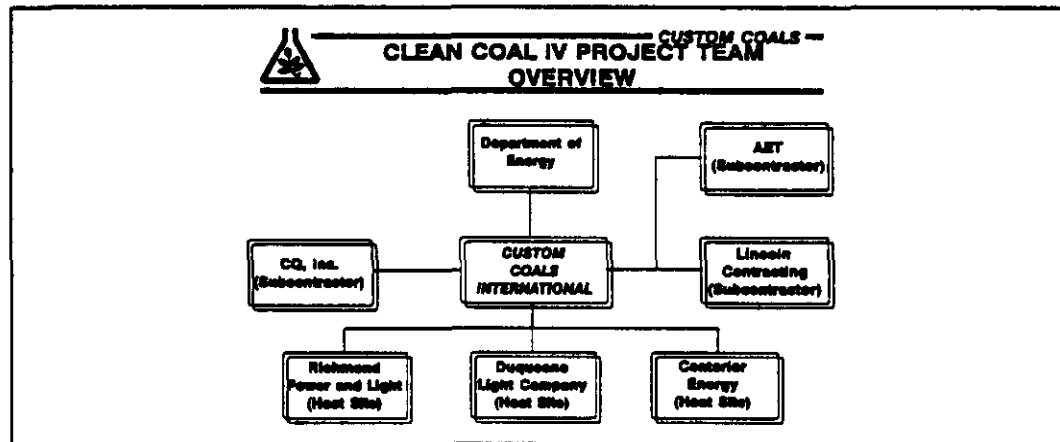
Through new coal preparation technologies, two compliance coal products can be produced by Custom Coals International (CCI) from most of the non-compliance coals east of the Mississippi River. They are termed Carefree Coal™ and Self-Scrubbing Coal™.

- Carefree Coal is produced solely through aggressive removal of ash and pyritic sulfur from non-compliance bituminous coal feedstocks. Carefree Coal is composed of coarse coal, fine coal and ultra fine coal. Some of the ultra fines may be briquetted.
- Self-Scrubbing Coal contains aggressively beneficiated coal with a limestone based additive. It is comprised of coarse coal, fine coal and briquettes. The additives are briquetted with the ultra-fine clean coal for convenience in handling.

For Self-Scrubbing Coal, the reduction of sulfur to compliance levels occurs in two stages. Pyrite, an iron-sulfur compound, is first removed by aggressive coal beneficiation. Sulfur dioxide, generated in the boiler from the coal's organic sulfur and residual pyritic sulfur, is then captured by the additives.

Carefree Coal and Self-Scrubbing Coal meet the year 2000 sulfur dioxide limitations. They are derived from local coals and, therefore, are compatible with the boiler; they are priced competitively with compliance coals imported into the local region; and no capital investment is required by the utility. The net effect of CCI's technologies is that they revalue many noncompliance reserves to compliance reserves.

The objective of our Clean Coal Technology program is to design and construct a 500 ton per hour coal cleaning plant equipped with our unique and innovative coal cleaning technology which will produce competitively priced compliance coals. These coals will then be test burned at three commercial utility power plants to demonstrate that these coals can meet the Clean Air Act Amendment sulfur reduction requirements.



Custom Coals, which has overall project management responsibility, has assembled an exceptional team for this project. Associated Engineering Technologies (AET), will design and Lincoln Contracting will construct the demonstration plant. CQ, Inc., which will test and operate the demonstration plant and manage the power plant field tests, is a recognized authority in coal cleaning plant design, testing and operation. A project management committee of senior executives from the participating companies will oversee project progress and performance.

The project costs and timetable are shown below. The preparation plant will be located in Somerset County, Pennsylvania. The host sites for the test burns are located in Richmond, Indiana, Cleveland, Ohio and Pittsburgh, Pennsylvania.

	Dates	Proposed Costs
<i>Pre-award</i>	October 1991 - October 1992	\$736,969
<i>Project Definition</i>	November 1992 - May 1993	2,000,000
<i>Engineering & Construction</i>	June 1993 - April 1995	49,200,000
<i>Operation</i>	May 1995 - March 1996	37,248,062
	TOTAL	\$89,185,031

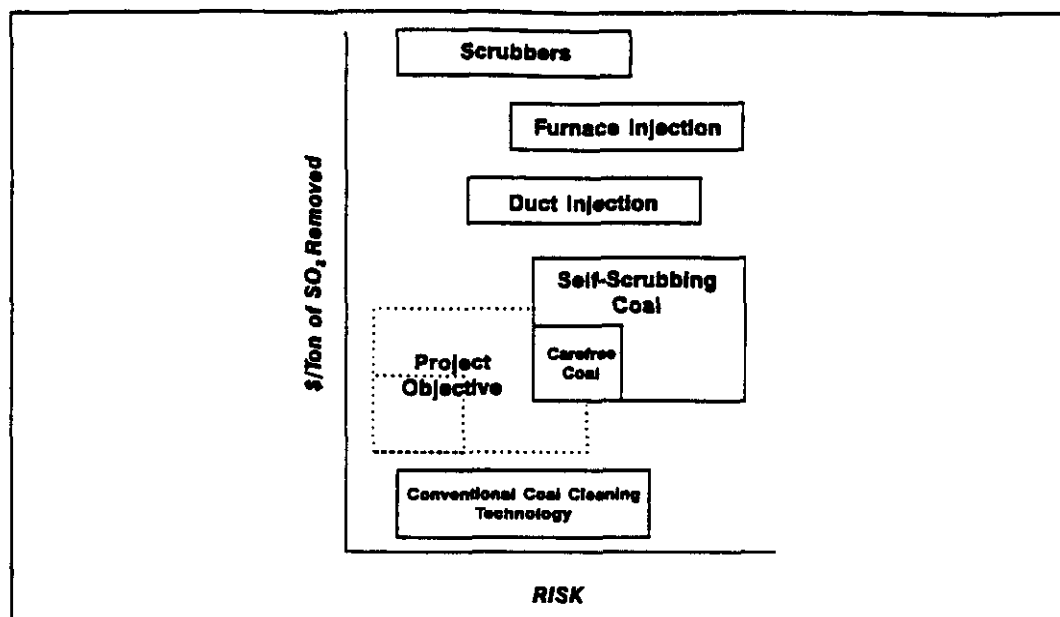
HISTORY OF TECHNOLOGY DEVELOPMENT

The Carefree Coal and Self-Scrubbing Coal technologies were developed through the proof-of-concept stage by Genesis Research Corporation, a small research and development company headquartered in Arizona. Dr. James Kelly Kindig, the inventor of the technology, had begun work on the technology in the late 1970's. A concerted effort to develop the products for commercial use began in the early 1980's. Funding during this stage of development was provided by equity raised from individual investors.

In 1988 Duquesne Light Company agreed to fund pilot scale testing of the technology. Cleaning tests in 2-inch cyclones were performed at CQ, Inc. and small-scale combustion testing occurred at Energy and Environmental Resources. The pilot scale test results supported Genesis Research claims of being able to reduce sulfur levels by up to 80%.

Given the encouraging pilot scale test results, in 1990 Duquesne agreed to fund commercial scale tests. Throughout 1990 and early 1991, a \$2 million test program was conducted and documented. All unique aspects of the coal cleaning technology were tested at commercial scale equipment sizes at CQ, Inc. Fine magnetite was prepared by Hazen Research, the cyclones were manufactured by Krebs Engineers and the magnetite recovery scheme was tested by Eriez Magnetics. The coal cleaning results in 10-inch cyclones substantially duplicated the performance achieved in the earlier 2-inch cyclone work. Combustion testing in 600,000 Btu/hour boilers at Energy and Environmental Resources also confirmed the earlier smaller scale results on sulfur capture in the boiler.

The full-scale demonstration provided by the Clean Coal Technology Program will provide the opportunity to blend all of the innovative aspects of the technology and prove the effectiveness of Self-Scrubbing Coal in reducing emissions. The demonstration will also prove the cost-effectiveness of the technology, paving the way to full commercialization of Self-Scrubbing Coal.



TECHNOLOGY DESCRIPTION

Raw coal may be viewed as an aggregation of three basic types of components. They are organic material, pyrite and rock. Each of these three materials is found free in raw coal. A large portion of raw coal, however, is comprised of two or all of these components locked together. It is this locking that creates the spectrum of specific gravities characteristic of coal.

Most conventional coal cleaning partitions raw coal into components: one less-than and the other greater-than some pre-selected specific gravity. Clean coal, the former, contains both free and locked particles. The locked particles, unfortunately, carry sulfur (from pyrite) and ash (from rock) into the marketable clean coal product. The refuse also contains both free and locked particles. Locked refuse particles contain organic material that constitutes a loss of coal (heating value) and, for the producer, a loss of revenue.

Locked particles are liberated in the Carefree process. This is a major factor distinguishing the Carefree process from conventional coal cleaning. Coarse locked particles are crushed to produce smaller particles. Most of the smaller particles are relatively free, depending upon the nature of the coal. The Carefree process embodies an efficient method for separating the large quantity of smaller, relatively free particles into clean coal and refuse. This also distinguishes the Carefree process from conventional coal cleaning.

The principal steps in the Carefree process include the following:

- Recover a low specific gravity (1.30), coarse (plus ½mm) clean coal product.
- Reject a high specific gravity (2.00), coarse refuse.
- Crush the resulting middling product (specific gravity 1.30 by 2.00) to liberate pyrite, other ash-forming minerals and coal.
- Size and classify the resulting minus ½mm comminuted and "natural" material into three fractions: fines, ultra-fines and slimes.
- Clean the fines and ultra-fines in dense medium cyclone circuits. These circuits employ magnetite that is an order-of-magnitude smaller than conventional magnetite, and cyclones of unique design. Recover the magnetite in circuits designed for the size of the coal and refuse particles.
- Dewater all the clean coal fractions: coarse, fine and ultra-fine. Some thermal drying may be required depending upon the coal.

Self-Scrubbing Coal is a compliance product prepared from non-compliance coals that have moderate organic sulfur and pyrite that liberates easily. The sulfur is removed in two steps, one occurs in the coal preparation plant, the other in the boiler. Self-Scrubbing Coal is first aggressively beneficiated, as described above. Both pyrite and ash are reduced as much as possible while at the same time maintaining a high Btu recovery. The sorbent: dolomite, limestone or dolomitic limestone, is then agglomerated (pelletized) with the ultra-fine fraction of the clean coal. The purpose of the sorbent is to capture the sulfur dioxide produced when the organic sulfur and residual pyrite are oxidized during combustion. The final clean coal product from the above process is Self-Scrubbing Coal. It is comprised of clean coarse coal, clean fines and pellets containing clean ultra-fine coal and sorbents.

As an example, Custom Coals evaluated a Lower Freeport coal from eastern Ohio. The raw coal has 6.4 lbs SO₂/MMBtu. The organic sulfur content is moderate and the pyrite liberates easily. A 1.2 pound compliance Self-Scrubbing Coal can be made from this feedstock.

Through aggressive beneficiation the 6.4 lbs SO₂/MMBtu in the raw coal can be reduced to 2.1 pounds. Cleaning to 2.1 pounds removes 67 percent of the total sulfur in the raw coal. To produce Self-Scrubbing Coal, limestone is pelletized with the ultra-fines and the pellets are combined with the clean coarse and clean fine coal. The calcium-to-sulfur stoichiometry in the resulting product is 2.4. An estimated 43 percent of the sulfur in this Self-Scrubbing Coal will be captured in the boiler through sulfation of the sorbent. Predictions of sulfur capture in the boiler are based upon data from the literature from full-scale plant and test-boiler evaluations of SO₂ capture by sorbents entering the boiler with the fuel. Sulfur-capture values, as a function of sorbent stoichiometry, will be confirmed by full-scale boiler test burns as part of the CC IV project. The final emission limit of 1.2 pounds of sulfur dioxide comprises a total sulfur reduction of 81 percent.

Analyses of the products from raw coal to Self-Scrubbing Coal are given in the following table:

Product	Ash, Percent	Lbs SO ₂ /MMBtu	Incremental SO ₂ Reduction Percent	Total SO ₂ Reduction Percent
<i>Raw Coal</i>	12.8	6.35	N/A	N/A
<i>Cleaned Coal</i>	3.7	2.08	67.2	67.2
<i>Self-Scrubbing Coal</i>	13.3	1.18	43.3	81.4

Several improvements result from using Self-Scrubbing Coal compared to earlier combustion trials by others in which the sorbent and coal were injected together through the burner.

- Less sintering occurs with low-NO_x burners which are expected to be installed by most utilities to comply with the NO_x reduction requirements of the 1990 Clean Air Act Amendments. Sintering causes a loss of sorbent reactivity due to a reduction in the surface area of the sorbent. Greater sintering occurs at higher temperatures and less at lower temperatures. Sintering is minimized by low-NO_x burners that provide an improved time/temperature profile for SO₂ capture.

- The quantity of ash is not excessive. Aggressively beneficiating the coal before introduction of the sorbent keeps ash levels near or below pre-established levels.
- Higher removals of sulfur dioxide are possible due to greater calcium-to-sulfur stoichiometry. The aggressive beneficiation reduces sulfur substantially. For a given quantity of sorbent, lower sulfur levels mean greater calcium-to-sulfur ratios. And, proportionately greater capture of sulfur dioxide occurs with higher calcium-to-sulfur ratios.
- The percent removal of sulfur dioxide is good. A capture of 43 percent by dry sorbent injection, that attained in the above example, would be considered poor if viewed as a stand-alone technology. When dry sorbent injection is integrated with CCI's aggressive coal cleaning process, total sulfur reduction is a very respectable 81 percent. This is sufficient to bring many coals into long-term compliance.

Self-Scrubbing Coal attains year-2000 compliance with coals of moderate organic sulfur and pyrite that liberates easily. No additions to or modifications of the boiler are required with Self-Scrubbing Coal. It is received, stored, reclaimed, pulverized and burned the same as conventionally prepared coal.

PLANT DESIGN

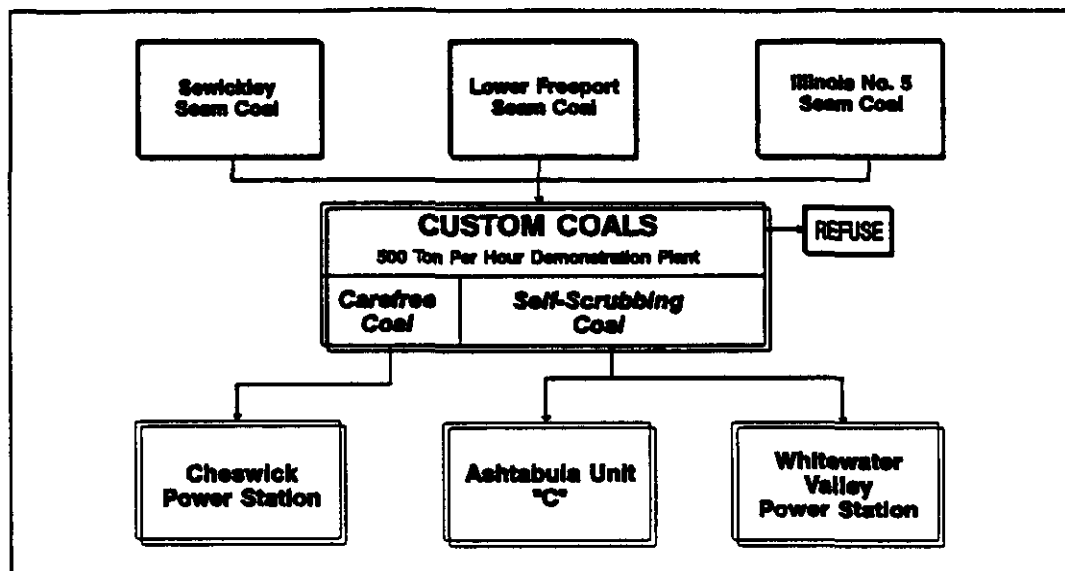
The preparation plant will be located in Central City, Pennsylvania, Somerset County, at the site of the existing idled Laurel Preparation Plant built in the late 1970's by Consolidated Coal. A substantial percentage of the handling facility infrastructure will be refurbished and reused. The preparation plant building itself will be demolished and replaced. The site will include the following sections:

- Raw Coal Handling - The site will be equipped to receive coal by truck. The raw coal handling system consists of a truck dump, raw coal conveyors, a 20,000 ton stockpile and a rotary breaker.

- Coarse Coal Circuit - A conventional heavy media cyclone circuit is used to clean the coarse material defined as 1½" by 1mm. The circuit is operated to remove very clean coal using a 1.30 specific gravity float and refuse material using a 1.75 specific gravity sink. The middlings material (1.30 sink by 1.75 float) is crushed and proceeds to the Fine or Ultrafine cleaning circuit depending on the resulting coal size.
- Fine Coal Circuit - In advance of the fine and ultra-fine cleaning circuits, a classifying cyclone circuit is used to remove the -500 mesh material consisting primarily of clay slimes. The fine coal cleaning circuit utilizes both a spiral concentrator and redesigned heavy media cyclones to achieve effective cleaning in the 1mm by 150 mesh size fraction. This heavy media circuit utilizes ultrafine magnetite to improve separation efficiency.
- Ultra-Fine Circuit - The ultra-fine magnetite and redesigned cyclones are also used to clean the 150-500 mesh material. The magnetite recovery system uses barium ferrite and rare earth magnetic separators to recover the ultra-fine magnetite.
- Coal Drying/ Pelletizing - Sorbent is mixed with ultra-fine clean coal which is then thermally dried and pelletized using a binder.
- Clean Coal Handling - Clean coal proceeds on a collecting conveyor through an automatic sampling system and on to three clean coal silos (5,000 tons each). From the silos either trucks or unit trains can be loaded. The plant has access to a Conrail siding on site.

TEST BURNS

The test burn phase of the project is comprised of test planning, coal preparation and combustion and data analysis and reporting. Test planning at each host site will include a detailed review of power plant performance records, a walk-down of each test unit to select appropriate access ports for test measurements, a meeting to discuss host utility requirements and test objectives and the preparation of a detailed test plan that documents required plant modifications to accommodate the test program, a test matrix of proposed operating conditions and measurements to be made during the test and a schedule for each of the tests to be conducted.



During each of the test burns, unit thermal performance will be determined for the entire combustion system - from the pulverizers to the precipitators. Specific coal samples, flue gas samples, ash and slag samples, pressures, temperatures and instrument data will be collected to determine energy consumption, efficiency and process performance for the combustion system. Comparison to design specifications and past performance will be the basis for measuring the costs and benefits of the test coals over a 30-day test period at steady-state baseload.

During the thermal performance tests, supplemental monitoring will be performed to measure environmental performance. On-line monitors, flue gas sampling and solids sampling will provide accurate measurements of:

- SO₂ emissions
- NO_x emissions
- CO₂ emissions
- Air toxics emissions
- Solid waste quantities and characteristics

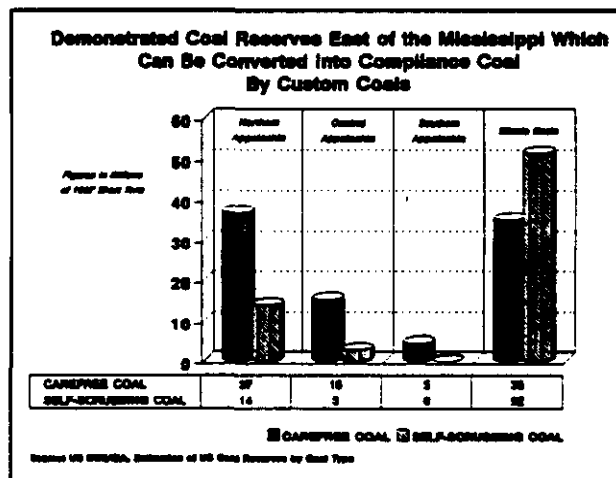
The results of the tests for each coal will be documented in detailed reports. These three reports will describe coal handling and sampling procedures, as-received coal quality of the test coals, power plant test procedures and data collected, results of data analyses and an assessment of the costs and benefits in terms of thermal performance and emissions for the test coals.

Custom Coals will facilitate technology transfer to the host utilities and to the utility industry as a whole. Technical briefings will be provided for each of the host utilities following completion of the respective field test efforts. The results of the field tests will also be presented at an appropriate national conference.

COMMERCIALIZATION

The current United States coal market is one billion tons per year. Of this, approximately 80% is sold to the electric utility industry. About 300 million tons of the utility industry consumption represents Western low-sulfur coal or unwashed strip mined coal. Of the remaining 500 million tons, Custom Coals has determined that at least half is burned in locations where strong economic or operating considerations could favor Self-Scrubbing Coal over alternate compliance solutions. Custom Coals seeks to achieve 10-20% share of this fraction of the market.

An analysis was performed of boilers affected by Phase I and Phase II of the Acid Rain Provisions. The best candidates for Carefree Coal and Self-Scrubbing Coal are thought to be those boilers over 20 years old and plants where scrubber retrofits are more costly. The analysis was combined with an assessment of available coals which can be brought into compliance with Custom Coals' technology as indicated in the following graph. From these combined analyses, the market size potential discussed above was developed.



Custom Coals' strategic plan is to acquire low cost non-compliance coal, bring it into compliance through the application of the technology and sell it near the avoided cost of other compliance alternatives. Custom Coals will construct a series of preparation plants to produce compliance coal products. The current forecast calls for 10 plants to be constructed in the United States by the year 2000.

A substantial market for Custom Coals' products is also developing in Eastern Europe. The Polish government has requested that a feasibility study be performed to assess the potential for constructing 14 coal cleaning plants with a total capacity of 50 million tons of coal per year. CCI has recently been awarded \$375,000 from U.S. AID to complete this study. Also, CCI, on April 29, 1993, received letters of intent from three Polish coal mines to build two coal preparation plants within the next two years that have a capacity of 10 million tons per year. Similar opportunities exist elsewhere in Eastern Europe and in the former Soviet Union.

The United States market is being approached by developing conceptual project opportunities using Custom Coals knowledge of the electric utility industry and the coal markets. Potential clean coal purchasers from the project are then contacted to determine if a sufficient level of interest exists to proceed with the project. Given a positive response, Custom Coals then identifies raw coal supplies and a preparation plant site. Coal industry consultants and coal preparation plant engineers are used to assist Custom Coals in developing the project concept into a series of contracts that can be project financed. In May 1992 Custom Coals executed an agreement with Chase Manhattan Bank, establishing a vehicle through which up to \$500 million of project financing capacity will be made available to construct at least 10 coal preparation plants.

Sales to Eastern Europe are being approached through the respective government entities as the coal supply and electric generating facilities are generally government owned. Again, coal industry consultants and coal preparation plant engineers are used to assess project opportunities and develop required contracts. Financing will be accomplished through bank loans guaranteed by international agencies and equity as required.

Custom Coals is also exploring the opportunities with the People's Republic of China, the biggest producer and consumer of coal in the world. Custom Coals would use its advanced coal cleaning technology to clean all or some of the coal currently being burned in the capital city of Beijing. Beijing, which is vying to host the Year 2000 Olympic Games although it has become one of the most polluted cities in the world, annually burns approximately 30 million tons of coal, all of it essentially unwashed. Beijing, as do other Chinese cities, relies on coal for some 80% of its energy use and a cleaner, more efficient coal will aid in resolving their environmental plight.

The cleaning costs should be fully offset by savings which would accrue from burning clean coal. For example, since the average rock content of the coal burned would be reduced from about 30% to 6%, rail costs would be reduced by some 24% and a comparable amount of scarce rail capacity would be released for alternate use. The program could be comprehensive and could include coal for utility boilers, industrial use, home and district heating and home cooking. A joint venture would be offered to the Chinese Government and to the Provincial Governments currently supplying coal to Beijing.

Initial discussions have also mentioned the possibilities for cleaning the rich coal reserves of Shanxi Province and to eventually transport some of the clean coal product of this North-West province to the more populous and industrial Eastern plain of China by pipeline or coal water slurry. This idea could be integrated with the Beijing Project.

THE HEALY CLEAN COAL PROJECT: DESIGN VERIFICATION TESTS

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ABSTRACT

As part of the Healy Clean Coal Project, TRW Inc., the supplier of the advanced slagging coal combustors, has successfully completed design verification tests on the major components of the combustion system at its Southern California test facility. These tests, which included the firing of a full-scale precombustor with a new non-storage direct coal feed system, supported the design of the Healy combustion system and its auxiliaries performed under Phase 1 of the project. Two 350 million BTU/hr combustion systems have been designed and are now ready for fabrication and erection, as part of Phase 2 of the project. These systems, along with a back-end Spray Dryer Absorber system, designed and supplied by Joy Technologies, will be integrated with a Foster Wheeler boiler for the 50 MWe power plant at Healy, Alaska. This paper describes the design verification tests and the current status of the project.

For presentation at the Second Annual Clean Coal Technology Conference, September 7-9, 1993, Co-Sponsored by the Department of Energy and Southern States Energy Board.

Part 1: Design Verification Tests

1.0 Introduction

The Healy Clean Coal Project (HCCP) was selected in December 1989 as one of the U.S. Department of Energy's Clean Coal Technology III programs under the sponsorship of Alaska Industrial Development and Export Authority (AIDEA). The goal of the HCCP is to design, fabricate, erect and operate a 50 MWe new coal-fired power plant at Healy, Alaska, based on advanced slagging coal combustion and flue gas desulfurization technologies for reducing NO_x and SO_2 emissions below current standards. The status of the HCCP and the roles of its major team members are described in Part 2 of this paper.

Figure 1 illustrates the basic schematic of the HCCP, highlighting the scope of supply of TRW and Joy Technologies, Inc., the suppliers of the advanced technologies. The major components of TRW's scope of supply consist of two 350 MMBTU/hr slagging combustors, two coal feed systems and one limestone feed system. Each slagging combustor consists of a precombustor, a slagging combustor and the associated high pressure cooling water system as its major subcomponents.

After the successful firing of a typical Healy coal in a 40 MMBTU/hr TRW slagging coal combustion system at TRW's Cleveland facility during 1990-1991 time frame, it was recognized early on that in the scale-up from 40 MMBTU/hr to 350 MMBTU/hr, the most critical components of the combustion system were the precombustor and the coal feed system. Therefore, to minimize project risk it was decided to conduct design verification tests on a scaled-up precombustor and a coal feed system prior to completing the final design. At that time, the slagging combustor scaling and operation was well understood, both from analytical and operational viewpoints; the limestone feed system was also operated successfully at the Cleveland facility. This experience was sufficient to allow scaling of these components to 350 MMBTU/hr without further testing.

Early in the design phase of the HCCP, it was recognized that a storage type of coal feed system, used in the Cleveland facility, was not desirable for the HCCP primarily due to safety concerns associated with the high volatile content of the Healy coals. Therefore, it was decided not to scale up the storage type of coal feed system, but to design, fabricate and test a new non-storage type direct coal feed system. Since the precombustor firing rate is 130 MMBTU/hr for a 350 MMBTU/hr slagging combustion system, it was decided to design, fabricate and test in conjunction with the precombustor a coal feed system also rated at 130 MMBTU/hr.

Part 1 of this paper covers the activities associated with the design, fabrication, installation and testing of a full-scale precombustor and an approximately one-third scale direct coal feed

system (DCFS), each rated at 130 MMBTU/hr, at TRW's Fossil Energy Test Site in San Juan Capistrano, California. These design verification tests (DVT) were performed during the period August 1992 to February 1993. Figure 2 illustrates the DVT schedule in relationship with the total TRW Phase 1 design schedule. Both the combustor and coal feed system hardware design were supported by cold-flow tests conducted at TRW's Space Park facility, as illustrated in this figure.

The precombustor design was scaled from TRW's design of the 40 MMBTU/hr system in Cleveland, a scale-up by a factor of approximately 10. A significant change in the design approach was necessitated by the requirement that the precombustor be used for boiler warm-up and that during that time all the coal fines from the mill be combusted prior to entering the cold furnace. Also, because of scaling, it was recognized early that a multiple coal injector would be advantageous and to this end a commercial Foster Wheeler coal burner was incorporated into this design. The new DCFS was conceived, designed, fabricated, installed and tested all within a span of approximately one year. The successful completion of the tests mitigated the concerns on scale-up and operation of the total system.

Over 200 tons of Healy Performance Blend coal were supplied gratis by Usibelli Coal Mine Company for these tests. The coal was transported from Usibelli mine to Energy and Environmental Research Corporation (EERC) in Irvine, California by barge and rail cars. EERC pulverized this coal to TRW's specifications and a total of 160 tons was delivered to TRW's test site in hopper cars. Figure 3 lists the properties of the pulverized coal. This coal was stored in tanks and blanketed with nitrogen for safety reasons, and used during the tests as needed. All of the pulverized coal was utilized in a series of 28 tests. The total run time on coal was approximately 43 hours.

2.0 Test Hardware

Figure 4 depicts a three-dimensional overview of Cell No. 3 at the Fossil Energy Test Site (FETS), a facility dedicated to fossil fuel combustion research and development at TRW's Capistrano Test Site, located about 65 miles south of Los Angeles, California. A photograph of the test site is shown in Figure 5.

2.1 DVT Precombustor

A full-scale DVT precombustor was used to verify the Healy precombustor design by hot-firing with Healy Performance Blend coal. The design of the precombustor and the DVT system were completed during September 1991 - March 1992. The precombustor consisted of five subassemblies: Foster Wheeler coal burner with primary windbox and Forney ignitor, combustion chamber with secondary windbox, mill air spool (including splitter), transition

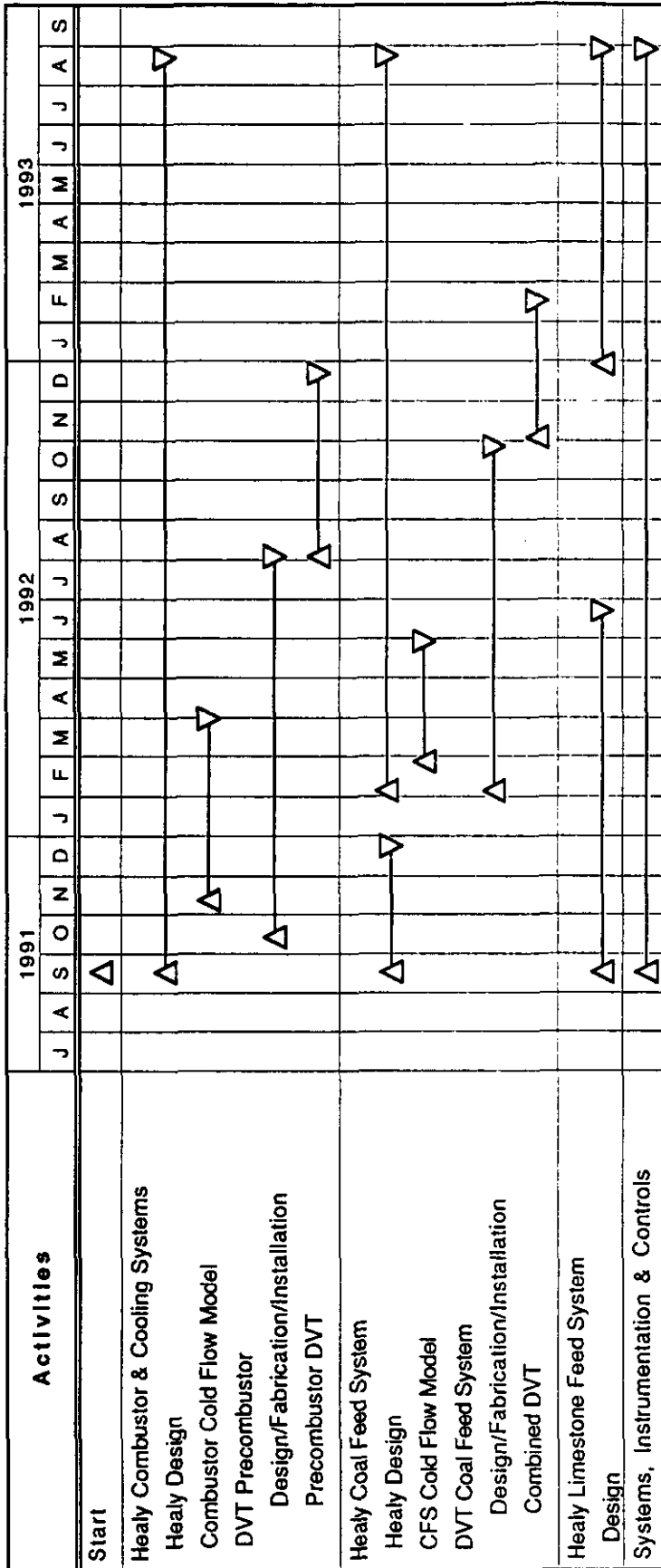


Figure 2: TRW Phase 1 Design Schedule

	<u>AS RECEIVED</u>	<u>DRY BASIS</u>
<u>PROXIMATE ANALYSIS</u>		
% MOISTURE	11.64	XXXXX
% ASH	17.15	19.41
% VOLATILE	39.59	44.80
% FIXED CARBON	<u>31.62</u>	<u>35.79</u>
	100.00	100.00
BTU/LB	8292	9384
<u>ULTIMATE ANALYSIS</u>		
% MOISTURE	11.64	XXXXX
% CARBON	49.83	56.39
% HYDROGEN	3.46	3.92
% NITROGEN	0.66	0.75
% SULFUR	0.14	0.16
% ASH	17.15	19.41
% OXYGEN (BY DIFF)	<u>17.12</u>	<u>19.37</u>
	100.00	100.00
<u>ASH ANALYSIS</u>		
	<u>WT %, IGNITED BASIS</u>	
SILICON DIOXIDE	55.68	
ALUMINUM OXIDE	12.81	
TITANIUM DIOXIDE	0.54	
IRON OXIDE	4.71	
CALCIUM OXIDE	14.75	
MAGNESIUM OXIDE	2.25	
POTASSIUM OXIDE	2.84	
SODIUM OXIDE	1.84	
SULFUR TRIOXIDE	3.67	
PHOSPHORUS PENTOXIDE	0.16	
STRONTIUM OXIDE	0.19	
BARIUM OXIDE	0.43	
MANGANESE OXIDE	0.13	
UNDETERMINED	<u>0.00</u>	
	100.00	
SILICA VALUE	71.95	
BASE: ACID RATIO	0.38	
T ₂₅₀ TEMPERATURE	2433 °F	
SIZE DISTRIBUTION	50 - 60% THROUGH 200 MESH	

FIGURE 3: PERFORMANCE BLEND COAL PROPERTIES

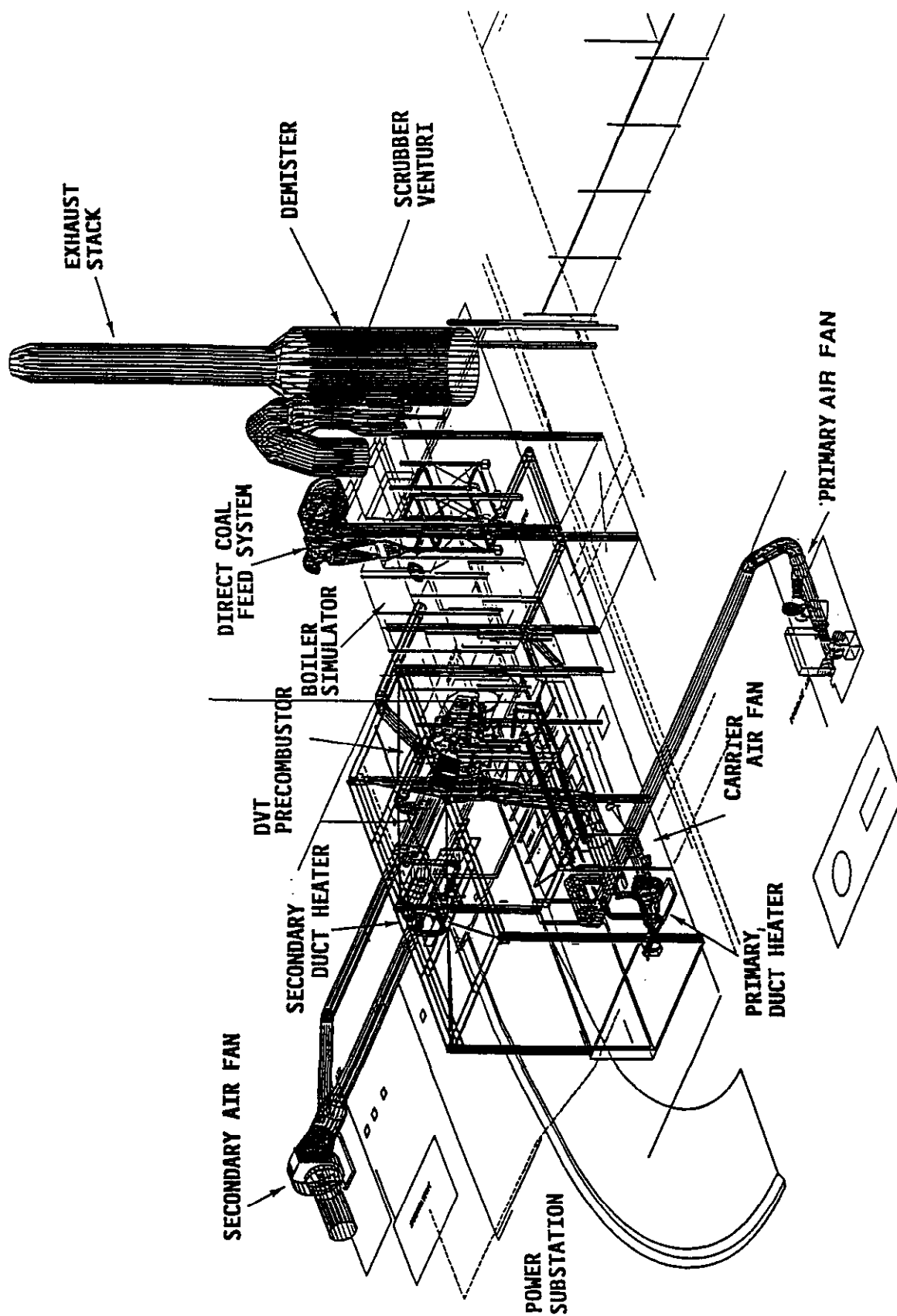


Figure 4 Fossil Energy Test Site, Cell No. 3 Overview

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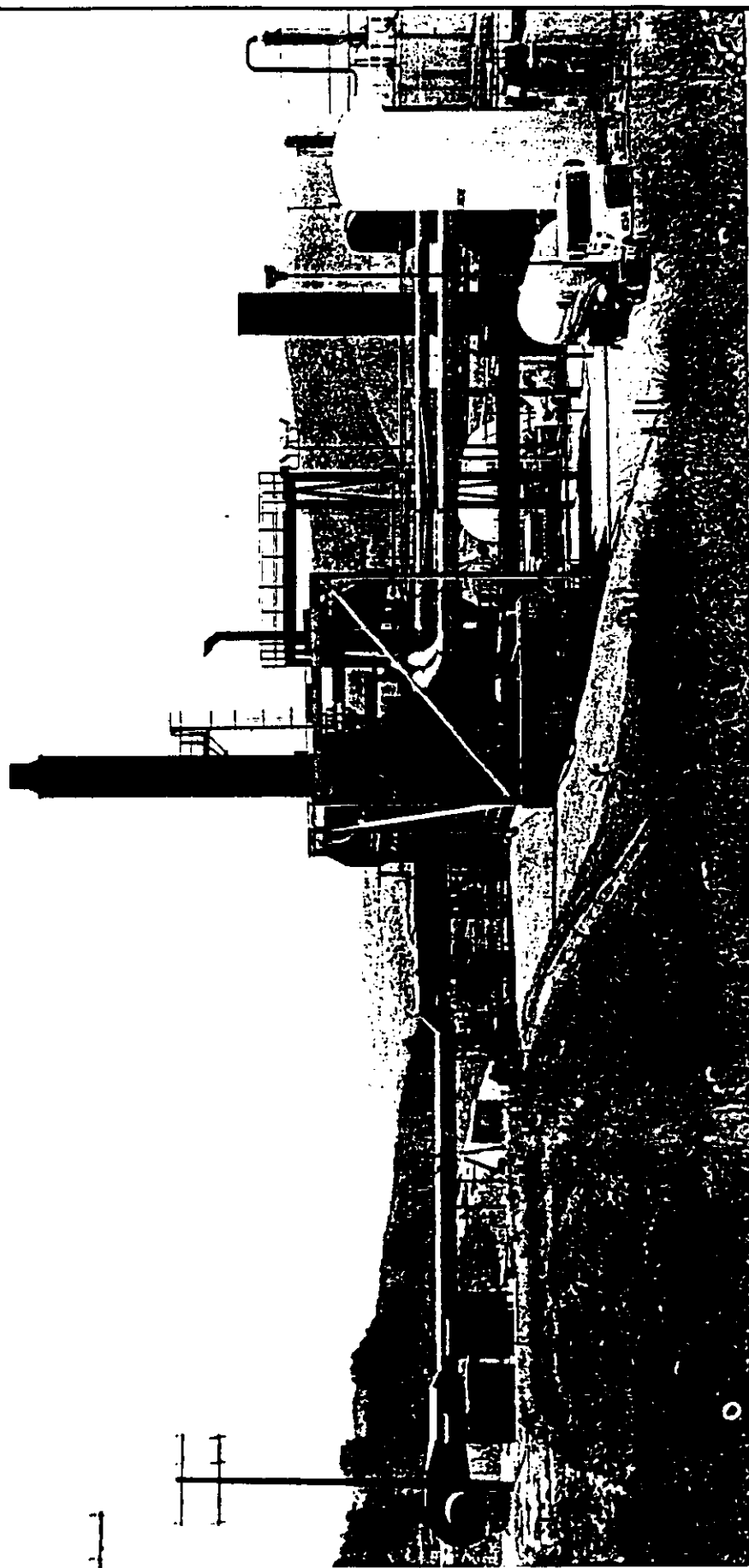


Figure 5 Test Cell No. 3 at Capistrano Test Site

section, and swirl dampers. A cross sectional view of the DVT precombustor is shown in Figure 6. Each subassembly is described separately in the following sections. The DVT precombustor overall dimensions, including the burner, were 18' as measured from burner flange to transition flange, with a maximum diameter of 10'. The dry weight of entire assembly, including refractory was approximately 38,000 lbs.

2.1.1 Fabrication and Installation

The fabrication of the precombustor was subcontracted to Monroe Inc. Figure 7 shows a view of the combustion chamber during fabrication. A very tight schedule was maintained to deliver the hardware by truck from Pittsburgh and to install it at TRW's test site on time.

The downstream transition and mount sections were installed first without the refractory which was provided later. The precombustor, Foster Wheeler coal burner, and Forney oil burner were preassembled on the ground and the refractory was installed. An overhead crane lifted and held the assembled unit in place while it was secured to a specially designed and fabricated support system. The final connections of air supply ducts, cooling water supply and return lines, etc., were field fabricated to assure fit-up. Figure 8 illustrates the fully installed view of the precombustor on the test stand. Leak and cold flow checks were performed prior to the first lightoff.

Most of the features of the DVT precombustor were identical to the Healy design. Figure 9 compares features of the DVT and Healy designs.

2.1.2 Foster Wheeler Burner/Primary Air Windbox

This subassembly consisted of a commercial-design Foster Wheeler coal burner and a primary air windbox. The primary air windbox interfaced with the facility air system to provide air to the Foster Wheeler burner. A Foster Wheeler dual air register within the primary windbox controlled both swirl and distribution of air to the burner.

2.1.3 Forney Oil Burner

The Forney oil burner system as delivered consisted of a retractable oil gun assembly with removable tip and swirler. Cold tertiary air was supplied by a separate fan. The air flowed into a housing which is part of the Foster Wheeler burner assembly surrounding the oil gun. The air provided external cooling for the oil gun, purged the housing cavity, and added swirling air into the oil flame for flame stabilization purposes.

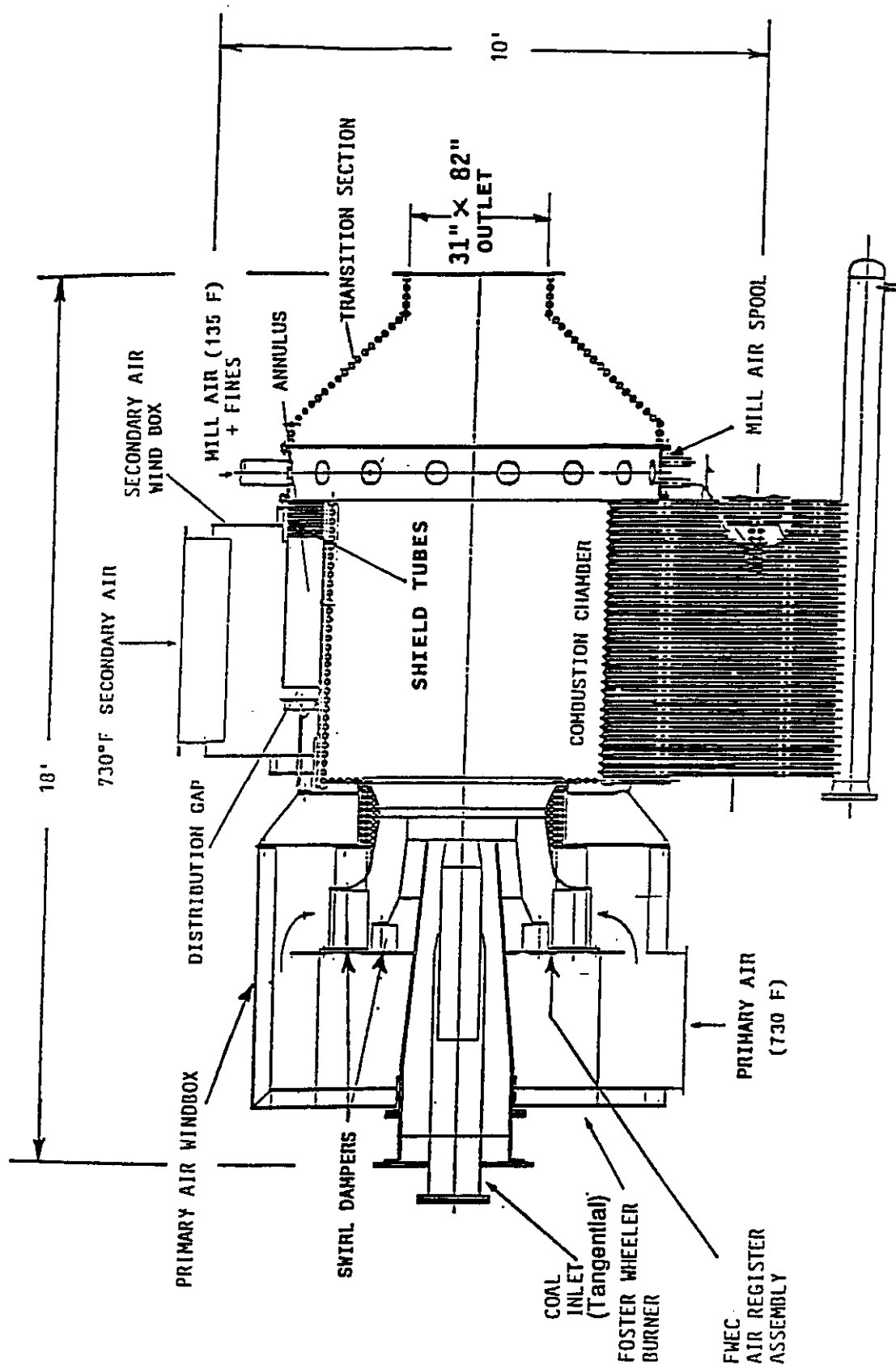


Figure 6 DVT Precombustor Configuration

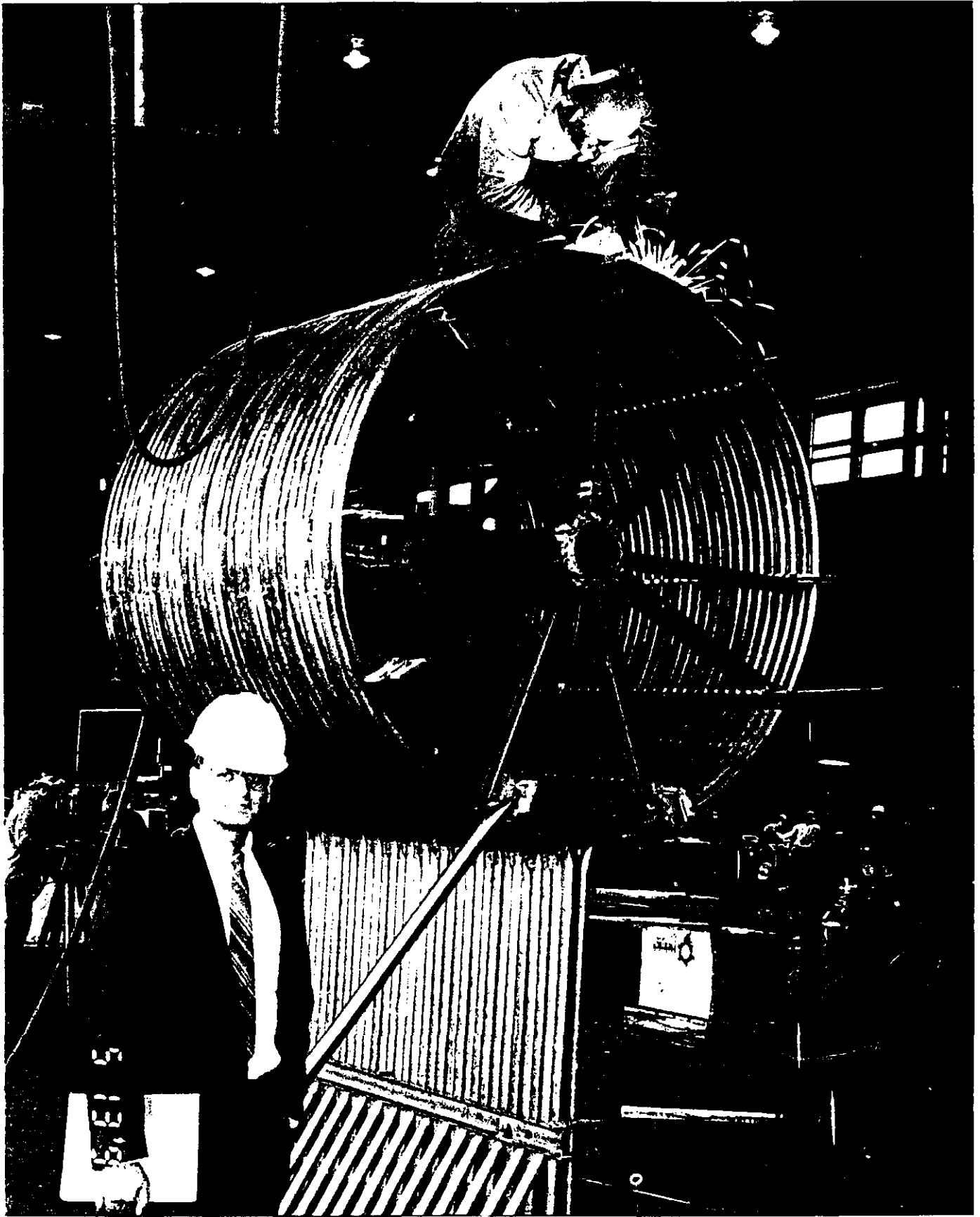


Figure 7 DVT Precombustor Shell During Fabrication

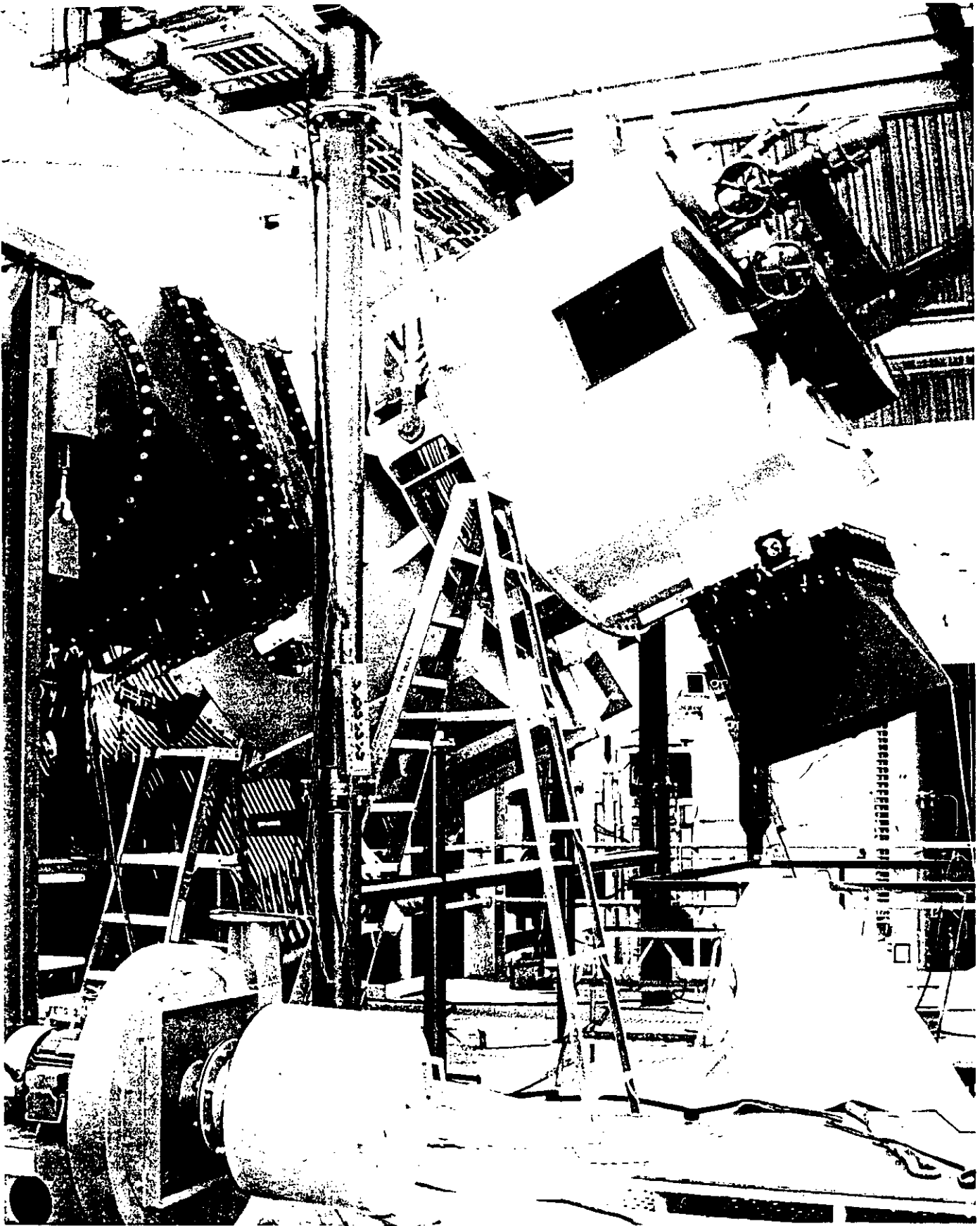


Figure 8 DVT Precombustor Installation

<u>FEATURES</u>	<u>DVT</u>	<u>HEALY</u>
COMBUSTION CHAMBER DIMENSIONS	62" I.D. X 62" L	62" I.D. X 62" L
BURNER THROAT DIAMETER	37"	37"
COAL BURNER TYPE	FWEC SPLIT FLAME, W/O WEAR LINERS	FWEC SPLIT FLAME WITH LINERS
OIL IGNITOR TYPE	FORNEY 70 MMBTU/HR	FORNEY 70 MMBTU/HR
PRECOMBUSTOR EXIT DIMENSIONS	31" X 82"	31" X 82"
COOLING WATER	100 °F, 150 PSI	592 °F, 1405 PSI
COOLING CIRCUIT GEOMETRY	SINGLE FULL LOOP (360°)	TWO HALF LOOPS (180°)
MILL AIR INJECTION COOLING	SEPARATELY COOLED SPOOL	INTEGRAL WITH WATER WALL
MILL AIR INJECTION PORTS	16 - 4.813" I.D.	6 - 5.5" I.D.
MIX ANNULUS WINDBOX INLET	1 - 45" X 45"	2 - 40" I.D.
TUBE DIMENSIONS	1.50" O.D. X 0.25" MWT	1.50" O.D. X 0.18" MWT
TUBE INSIDE SURFACE	RIBBED	SMOOTH
TUBE MATERIAL	SA-210 GR A-1	SA-213 T2
MEMBRANE DIMENSIONS	0.50" WIDE X 0.50" THICK	0.75" WIDE X 0.25" THICK
MEMBRANE MATERIAL	SA-515 GR 60	SA-387 GR 11

FIGURE 9: PRECOMBUSTOR FEATURES, DVT VERSUS HEALY

2.1.4 Combustion Chamber/Secondary Air Windbox

Figure 6 shows the secondary air windbox and water-cooled combustion chamber. The windbox interfaces with facility air system to provide air downstream of the chamber. A refractory-lined combustion chamber was constructed using a tube membrane design with 1.5" ribbed tubing (0.24" MWT) illustrated in Figure 10. The 62" diameter chamber was enclosed by the secondary air windbox.

2.1.5 Mill Air Spool

The 82" diameter mill air spool, shown in Figure 11, was constructed with a water-cooled, double wall design. The function of this spool was to direct mill air laden with coal fines primarily during boiler warm-up to the precombustor downstream of the Foster Wheeler burner. A coal splitter upstream of the mill air spool distributed coal fines to precombustor through 8 individual 5" diameter ports. Diagnostic precombustor gas pressure was measured in this component.

2.1.6 Transition Section and Swirl Damper Assembly

This subassembly provided a transition from the 82" diameter chamber to the 31"x82" rectangle required at the slagging combustor inlet, as shown in Figure 12. The mechanical design was based on a water-cooled tube membrane design similar to the combustion chamber construction. A swirl damper assembly, consisting of a housing and two damper blades, was also designed, fabricated and installed at the rectangular exit of the transition section. The components of this assembly were constructed based on a water-cooled tube membrane design. A key function of the blades is to maintain minimum gas velocity at the precombustor outlet. Remote actuation of blade position allowed operators to control blade position individually, or as a pair, during 100% MCR load conditions.

A video camera located in swirl housing sidewall provided a useful diagnostic tool for evaluating flame stability over various operating conditions. In addition, the camera images confirmed both damper blades and housing remained free of ash attachment during the entire DVT series.

2.2 DVT Direct Coal Feed System (DCFS)

Figure 13 shows a schematic of the DCFS, consisting of primarily a variable splitter followed by two blowdown cyclones. The discharge from the one of the two blowdown cyclones feeds the precombustor and the discharge from the other feeds the slagging combustor (or a collection tank during the DVT.)

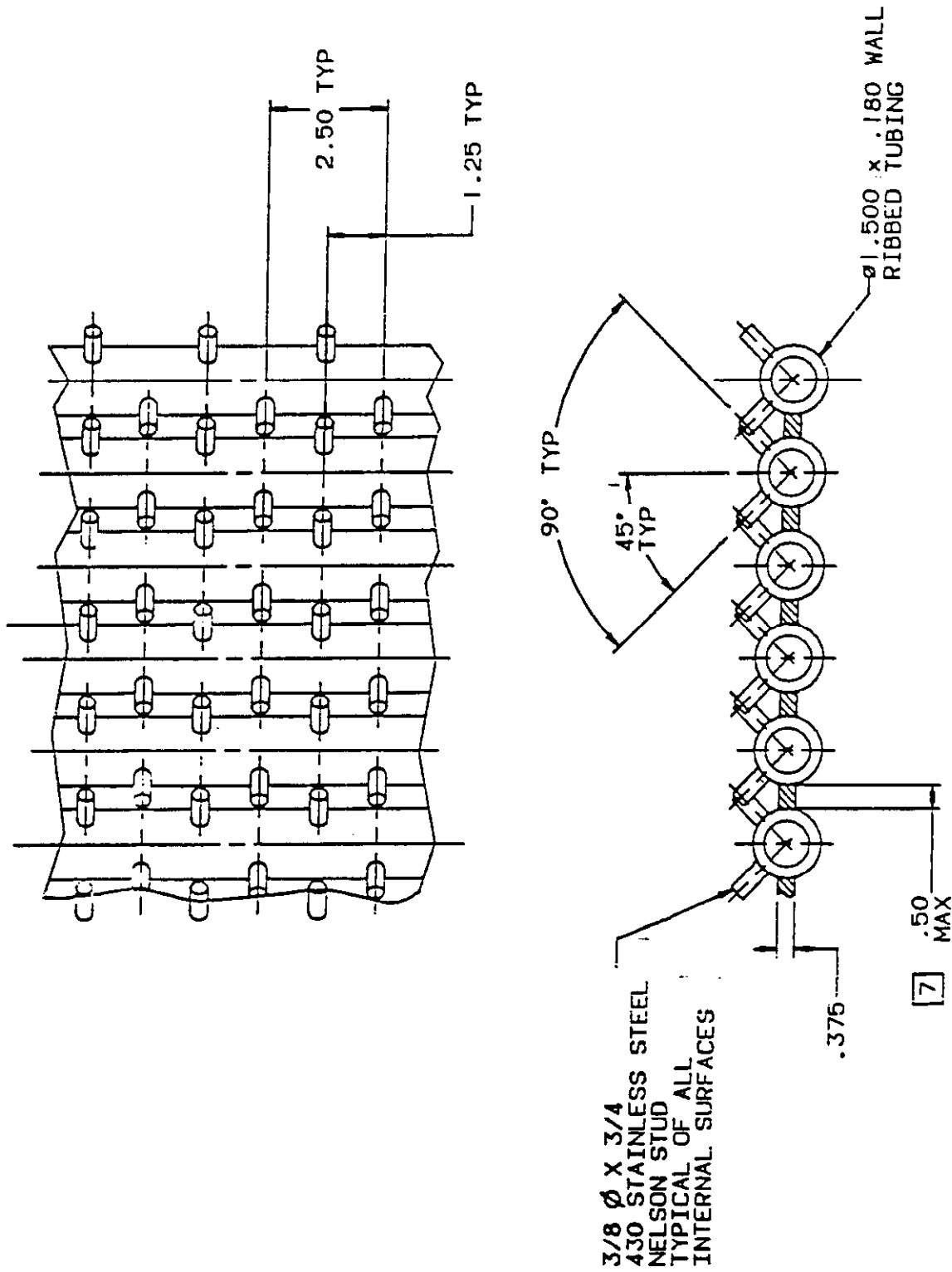


Figure 10 DVT Precombustor Stud Pattern for Refractory Retention



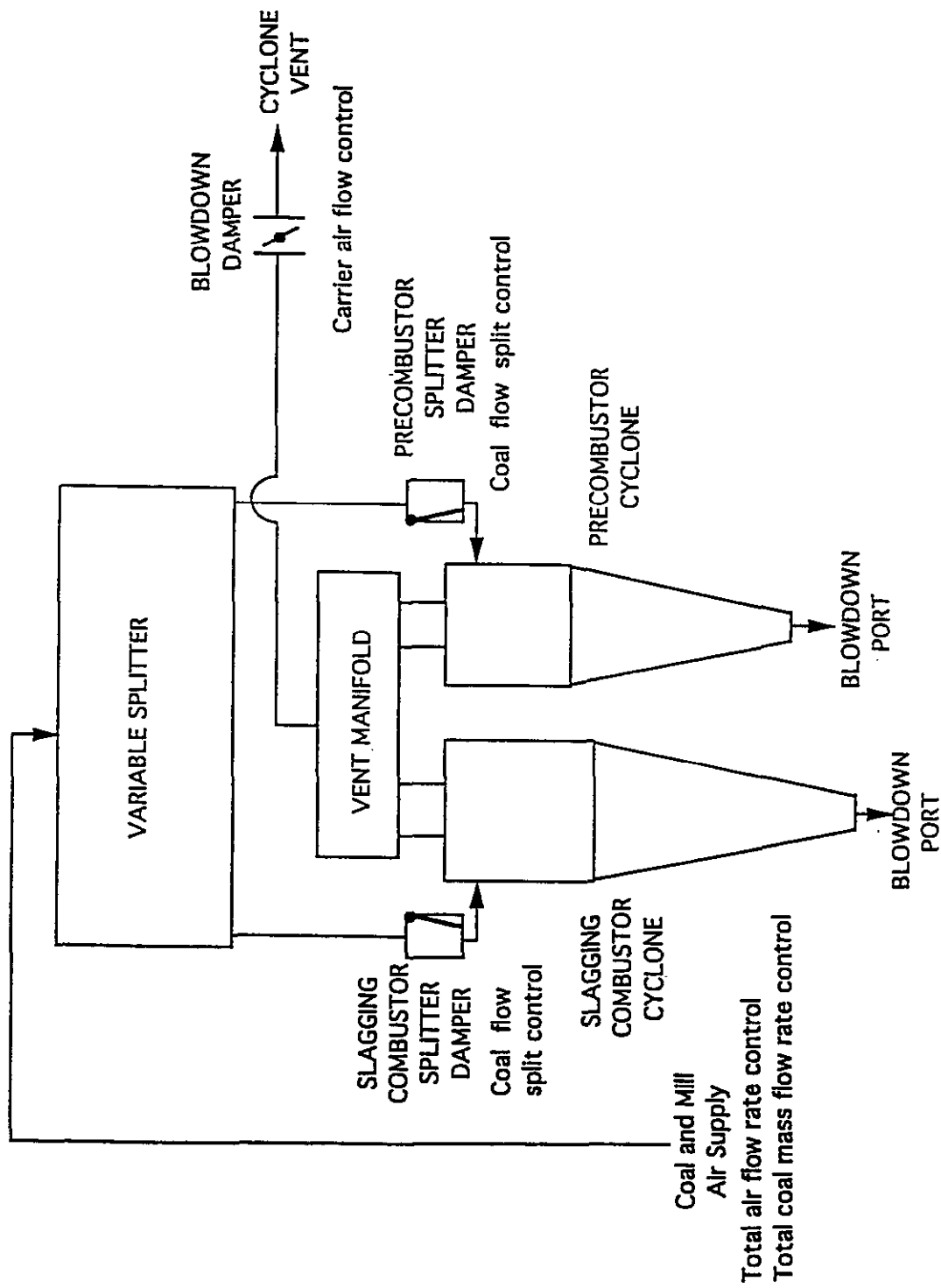


Figure 13 Direct Coal Feed System Schematic

The design of the variable splitter and the blowdown cyclones was based initially on TRW's concept evaluation and analytical calculations. The DCFS concept was then tested a one-tenth scale cold flow model prior to the DVT hardware fabrication. Talcum powder was used to simulate coal in the cold flow modeling tests. After the successful completion of the cold flow tests, the design of the one-third scale DCFS was finalized. TRW's subcontractor, Delta Ducon, prepared the final detailed design and fabrication drawings. This DCFS matched the full-scale rating of the precombustor since the precombustor utilizes approximately one-third of the total coal flow.

2.2.1 Configuration

The DVT series was planned for two DCFS configurations: One configuration was for firing the precombustor at full load with the total coal flow from both the outlet legs of the DCFS. The other configuration was in the split mode, with only the split coal stream used for firing the precombustor while the other (which would have fired the slagging combustor) was just collected and weighed.

The DVT DCFS was designed and constructed so that if and when problems were encountered with the DCFS, precombustor testing could still be continued using the existing facility coal feed system simply by closing and opening manual valves without any hardware changes such that coal could be directed from the facility system to the precombustor without flowing through the DCFS.

A CO monitor was installed in the vent line of the DCFS to monitor CO levels during testing for detecting fires, if any. A CO₂ fire extinguishing system was also connected to the coal feed system in the event a problem occurred. Water deluge ports were also incorporated into the design for fire extinguishing.

Access and observation ports were installed at critical locations to inspect for coal accumulations.

2.2.2 Installation

The precombustor coal transport line assembly was installed at the same time as the precombustor was installed to allow testing just the precombustor. The remaining DCFS components were installed during night shifts on a non-interference basis while the precombustor test series was being completed.

2.3 Facility Systems

Combustion air for DVT precombustor testing was provided by the primary and secondary air systems. Each system was complete with

electric fan, power substation, oil-fired duct heater, flow control and diagnostic measurement equipment. The DVT precombustor was mounted to a boiler simulator in the same orientation relative to gravity, as in the Healy application. The boiler simulator was a rectangular chamber with flood-cooled water walls. The simulator provided residence time for radiant cooling of the exhaust gases prior to a water quench. The downstream support equipment required to meet the Southern California Air Quality Management District regulations consisted of a quench system, scrubber system, and exhaust stack.

3.0 Objectives of Design Verification Tests

The design verification tests (DVT) were performed as part of the total design of the TRW coal combustion system for the Healy plant primarily to mitigate the risks associated with the scale-up of the precombustor and the direct coal feed system.

The tests were grouped into two major categories: (1) Full-scale precombustor tests only, using the existing coal feed system at TRW's Capistrano Test Site (CTS), (2) Flow, check-out and hot-fire tests of the one-third scale direct coal feed system coupled to the precombustor. Specific objectives are delineated in Figure 14.

4.0 Design Verification Test Logic

Figure 15 shows the design verification test logic. Since the precombustor was designed, fabricated and installed significantly earlier than the DCFS, the precombustor tests were first performed using the existing facility coal feed system, and in parallel, the DCFS was fabricated and installed at CTS. This was accomplished by operating the site on two shifts. The timing was important to complete the installation of the DCFS just prior to the time the precombustor testing was completed. The precombustor testing consisted of the following major tasks:

- o Coal Lightoff
- o Coal Firing
- o Burner Tuning
- o Swirl Damper Check out
- o Load/Stoichiometry Series
- o Load/Preheat Series
- o Healy Light-off/Warmup Sequences
- o Swirl Damper Evaluation

The following tasks were performed during the DCFS tests:

- o Cyclone Efficiency Evaluation
- o Blowdown Control and Evaluation
- o Evaluation and Improvement of Flow Stability
- o Evaluation and Elimination of Coal Accumulation in the Lines

	<u>PC</u> <u>TESTS</u>	<u>DCFS-PC</u> <u>TESTS</u>
PROOF OF CONCEPT		X
VALIDATE SCALE-UP	X	X
VALIDATE STABILITY, PERFORMANCE	X	X
VALIDATE IGNITION, FLAME-HOLDING	X	X
DISPOSITION OF CYCLONE VENT AIR		X
STARTUP AND SHUTDOWN SEQUENCES	X	X
MEASURE HEAT FLUXES	X	X
MEASURE PRESSURES/PRESSURE DROPS	X	X
DEMONSTRATE FWEC BURNER	X	X
DEMONSTRATE FORNEY IGNITOR	X	X
DEMONSTRATE SAFE OPERATION	X	X
OBTAIN DESIGN DATA	X	X
IDENTIFY DESIGN CHANGES, IF ANY	X	X

FIGURE 14: DESIGN VERIFICATION TEST OBJECTIVES

o Evaluation and Minimization of Pressure Drops

The only activity which was eliminated from the original logic in Figure 15 was the Captive Flow Test. The original plan called for evaluating cyclone performance with coal prior to the actual hot firing into the precombustor. However, it was determined that it was more expeditious, safer and less expensive to perform these tests while firing the precombustor. This was possible because by the time the DCFS was ready for operation, the precombustor had been completely checked out and could be operated reliably.

5.0 Test Results

5.1 Precombustor

Figure 16 summarizes the major precombustor issues which were addressed by the DVT, with applicable test results and the impact on the design and operation. Toward the conclusion of the precombustor tests a nominal accumulation of slag was noted on the lower edge of the water cooled combustion chamber and on adjacent hardware. The last three feet of the chamber had a wet slag appearance around the periphery, but no significant buildup. Analysis of the Performance Coal used throughout the test program indicated a T_{250} (temperature at which the molten ash viscosity is 250 poise) nearly 300 F less than that originally specified for that coal. This raised the concern that over long operating periods, a significant buildup of slag may interfere with the lower injection ports. The injection configuration was therefore changed as shown in Figure 17. In the modified configuration the number of injection ports was reduced from eight to six and the lower ports were eliminated.

5.2 Direct Coal Feed System

The tests utilizing the DCFS in conjunction with the pre-tested precombustor proved that the total pressure drop from the DCFS inlet to the boiler was within the 60 inches water pressure budget provided in the technical specification. Figure 18 illustrates the required DCFS inlet pressure as a function of the load. The DVT also assured that there was no need for additional eductors to transport the coal to the combustor.

Coal accumulations in the first version of the splitter discharge ducts occurred during attempts to achieve full load. After evaluating corrective solutions, both analytically and via cold flow modeling, a relatively simple modification to the splitter discharge duct design eliminated the accumulations, incurring an additional pressure drop of only 3 inches of water. This design change was incorporated into the full-scale Healy design.

Flow stability was also improved during the DVT through transport



Issue	Test Results	Design/Operation Impact
Coal burner performance including ignition, stability and load variation	<ul style="list-style-type: none"> o Demonstrated stable operation over the full load range o Demonstrated reliable coal light off o No flame failures experienced o Burner delta-P measured o Close agreement between measured and predicted stack oxygen o No significant fouling seen during test series o Portion of combustion can covered with thin (1/4-1/2") slag layer. Due to low T250 (2400F) o Some slag deposits seen in bottom of transition and near PC exit 	<ul style="list-style-type: none"> o High level of confidence in reliable burner operation at Healy o Adds margin to pressure budget o Good indication of high combustion efficiency
Prevention of slagging and fouling	<ul style="list-style-type: none"> o Demonstrated burning of fines during DVT coal feed system o No adverse effects on precombustor operation o No evidence of fouling due to coal fines o Successfully demonstrated Healy sequence including coal/oil exchange with oil ignitor at 70 MMBtu/hr o Measured heat loss slightly over target due to lack of refractory o Measured heat fluxes are within predicted range o Smokeless operation demonstrated at minimum (20 MMBtu/hr) and minimum (70 MMBtu/hr) loads. Slight stack haze at intermediate loads o Pressures for atomization and oil significantly higher than Forney estimates, exceeding plant capability. Changed operating mode to reduce pressures to reasonable levels. o Forney recommended tertiary air flow causes oil flame failure at low loads 	<ul style="list-style-type: none"> o No major impact. Will use lower stoichiometry for low T250 coals at Healy o Mill air injectors related for Healy design to avoid possible injector plugging o Precombustor can reliably burn fines as required during start-up at Healy
Combustion of cyclone vent air including coal fines	<ul style="list-style-type: none"> o Demonstrated burning of fines during DVT coal feed system o No adverse effects on precombustor operation o No evidence of fouling due to coal fines o Successfully demonstrated Healy sequence including coal/oil exchange with oil ignitor at 70 MMBtu/hr o Measured heat loss slightly over target due to lack of refractory o Measured heat fluxes are within predicted range o Smokeless operation demonstrated at minimum (20 MMBtu/hr) and minimum (70 MMBtu/hr) loads. Slight stack haze at intermediate loads o Pressures for atomization and oil significantly higher than Forney estimates, exceeding plant capability. Changed operating mode to reduce pressures to reasonable levels. o Forney recommended tertiary air flow causes oil flame failure at low loads 	<ul style="list-style-type: none"> o Validates method proposed for combustor start-up/shut-down o Healy design will include refractory lining throughout
Demonstration of Healy start-up and shut-down sequences	<ul style="list-style-type: none"> o Demonstrated burning of fines during DVT coal feed system o No adverse effects on precombustor operation o No evidence of fouling due to coal fines o Successfully demonstrated Healy sequence including coal/oil exchange with oil ignitor at 70 MMBtu/hr o Measured heat loss slightly over target due to lack of refractory o Measured heat fluxes are within predicted range o Smokeless operation demonstrated at minimum (20 MMBtu/hr) and minimum (70 MMBtu/hr) loads. Slight stack haze at intermediate loads o Pressures for atomization and oil significantly higher than Forney estimates, exceeding plant capability. Changed operating mode to reduce pressures to reasonable levels. o Forney recommended tertiary air flow causes oil flame failure at low loads 	<ul style="list-style-type: none"> o Required pressures for Healy Atomization: 95 psig Oil: 150 psig o Reduce tertiary air flow for Healy
Validating design heat fluxes and cooling loads	<ul style="list-style-type: none"> o Demonstrated burning of fines during DVT coal feed system o No adverse effects on precombustor operation o No evidence of fouling due to coal fines o Successfully demonstrated Healy sequence including coal/oil exchange with oil ignitor at 70 MMBtu/hr o Measured heat loss slightly over target due to lack of refractory o Measured heat fluxes are within predicted range o Smokeless operation demonstrated at minimum (20 MMBtu/hr) and minimum (70 MMBtu/hr) loads. Slight stack haze at intermediate loads o Pressures for atomization and oil significantly higher than Forney estimates, exceeding plant capability. Changed operating mode to reduce pressures to reasonable levels. o Forney recommended tertiary air flow causes oil flame failure at low loads 	<ul style="list-style-type: none"> o Healy design will include refractory lining throughout
Operation of 70 MMBtu/hr Forney oil burner	<ul style="list-style-type: none"> o Demonstrated burning of fines during DVT coal feed system o No adverse effects on precombustor operation o No evidence of fouling due to coal fines o Successfully demonstrated Healy sequence including coal/oil exchange with oil ignitor at 70 MMBtu/hr o Measured heat loss slightly over target due to lack of refractory o Measured heat fluxes are within predicted range o Smokeless operation demonstrated at minimum (20 MMBtu/hr) and minimum (70 MMBtu/hr) loads. Slight stack haze at intermediate loads o Pressures for atomization and oil significantly higher than Forney estimates, exceeding plant capability. Changed operating mode to reduce pressures to reasonable levels. o Forney recommended tertiary air flow causes oil flame failure at low loads 	<ul style="list-style-type: none"> o Required pressures for Healy Atomization: 95 psig Oil: 150 psig o Reduce tertiary air flow for Healy
Verify pressure budget for Healy design	<ul style="list-style-type: none"> o Demonstrated burning of fines during DVT coal feed system o No adverse effects on precombustor operation o No evidence of fouling due to coal fines o Successfully demonstrated Healy sequence including coal/oil exchange with oil ignitor at 70 MMBtu/hr o Measured heat loss slightly over target due to lack of refractory o Measured heat fluxes are within predicted range o Smokeless operation demonstrated at minimum (20 MMBtu/hr) and minimum (70 MMBtu/hr) loads. Slight stack haze at intermediate loads o Pressures for atomization and oil significantly higher than Forney estimates, exceeding plant capability. Changed operating mode to reduce pressures to reasonable levels. o Forney recommended tertiary air flow causes oil flame failure at low loads 	<ul style="list-style-type: none"> o Pressure budget leaves sufficient margin for flow control at Healy
Reliable operation of flame scanner system	<ul style="list-style-type: none"> o Demonstrated burning of fines during DVT coal feed system o No adverse effects on precombustor operation o No evidence of fouling due to coal fines o Successfully demonstrated Healy sequence including coal/oil exchange with oil ignitor at 70 MMBtu/hr o Measured heat loss slightly over target due to lack of refractory o Measured heat fluxes are within predicted range o Smokeless operation demonstrated at minimum (20 MMBtu/hr) and minimum (70 MMBtu/hr) loads. Slight stack haze at intermediate loads o Pressures for atomization and oil significantly higher than Forney estimates, exceeding plant capability. Changed operating mode to reduce pressures to reasonable levels. o Forney recommended tertiary air flow causes oil flame failure at low loads 	<ul style="list-style-type: none"> o DVT experience suggests that oil/coal flame discrimination may not be required for safe operation at Healy o Working to obtain resolution through NFPA and/or industry experience
Thermal effects, thermal mismatches	<ul style="list-style-type: none"> o Demonstrated burning of fines during DVT coal feed system o No adverse effects on precombustor operation o No evidence of fouling due to coal fines o Successfully demonstrated Healy sequence including coal/oil exchange with oil ignitor at 70 MMBtu/hr o Measured heat loss slightly over target due to lack of refractory o Measured heat fluxes are within predicted range o Smokeless operation demonstrated at minimum (20 MMBtu/hr) and minimum (70 MMBtu/hr) loads. Slight stack haze at intermediate loads o Pressures for atomization and oil significantly higher than Forney estimates, exceeding plant capability. Changed operating mode to reduce pressures to reasonable levels. o Forney recommended tertiary air flow causes oil flame failure at low loads 	<ul style="list-style-type: none"> o Redesign for Healy delta-T limited to 3000F o "Shield tubes" required for Healy design

Figure 16: Precombustor DVT Results

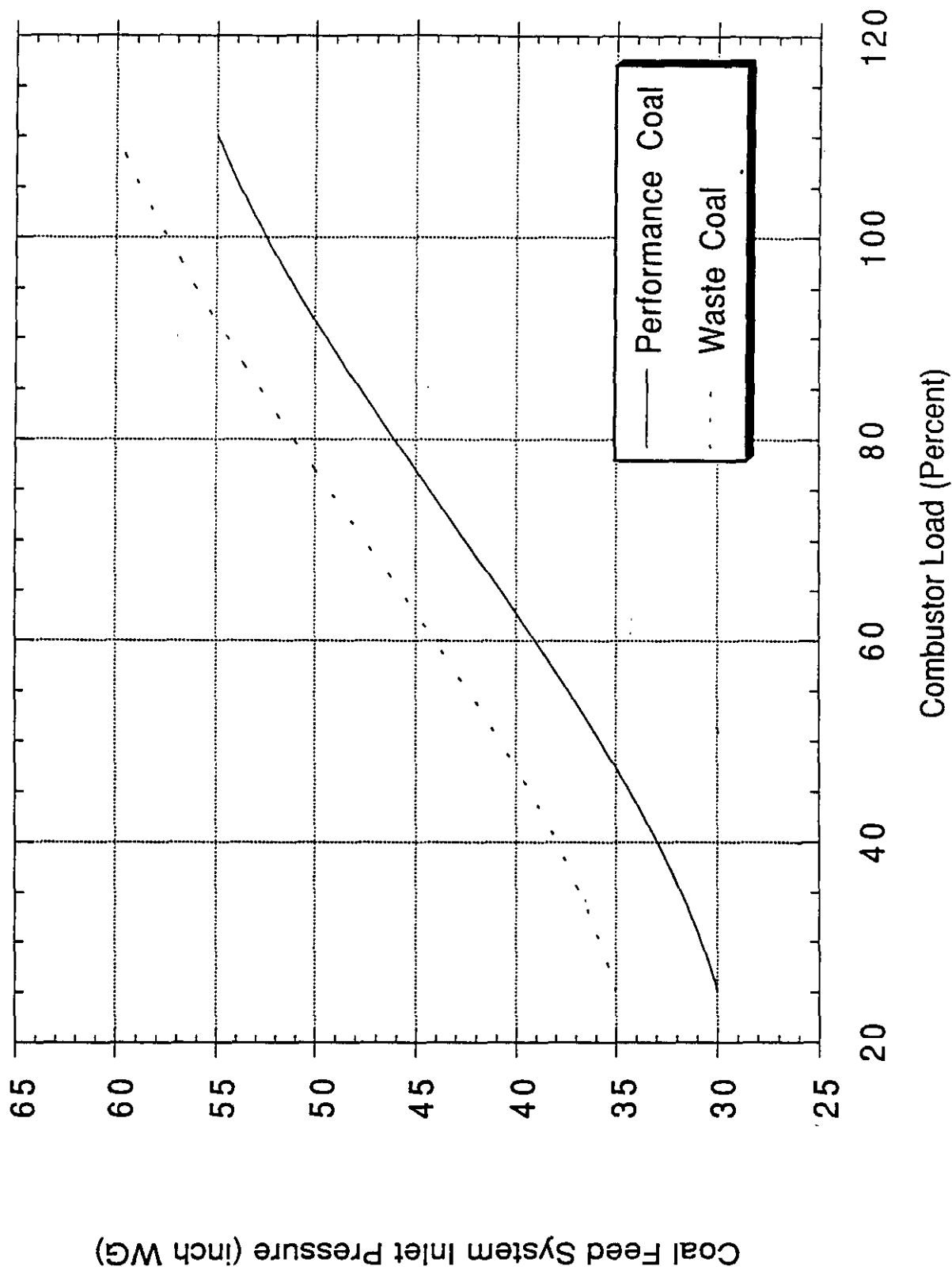


Figure 18 DCFS Inlet Pressure Requirements

line modifications as well as operational changes. Figure 19 illustrates the results of the hardware improvements. Peak to peak precombustor and burner pressure variations of 4 inches water were reduced to less than 2 inches of water after the transport line modifications were implemented.

Cyclone blowdown port size and blowdown leg diameter effects were also evaluated during testing. Minimum sizes were established based on pressure drop measurements and the total flow rates of air and coal per cross sectional area. Cyclone blowdown port sizes and blowdown pipe sizes were established for the Healy design in which the precombustor and the slagging combustor cyclones are sized in proportion to the total flow received by each cyclone.

Flow control was also improved during the DVT. Controlling the blowdown based on input from the annubar flow meter proved to be difficult to tune. The blowdown damper was either overdamped or underdamped in response to fluctuations in the input flow emanating from the mill air fan and lock hopper coal supply system. Therefore, an orifice plate was added upstream of the blowdown damper which enabled the damper to control in a more stable regime and be less responsive to fluctuations in total inlet flow. Figure 20 illustrates stable precombustor and burner pressures even though flow from the facility coal supply system experienced fluctuations due to periodic coal transfers. The DCFS dampened the fluctuations in the supply pressure, a feature which is valuable in the Healy design since an exhaustor fan is located upstream of each DCFS.

A method for ascertaining velocity and margin above the saltation was also determined during the DVT. The precombustor burner pressure drop proved to be a reliable metric for predicting flow velocities.

7.0 Conclusions

The results of the design verification tests and their impact on the Healy design are summarized below:

- o The tests validated the basic sizing, geometry and operation of the precombustor. The Healy precombustor design was modified to include structural improvements based on a few thermal stress problems observed during the tests.
- o The tests proved that the departures from the Cleveland precombustor design were beneficial as exemplified by (i) the validation of the new mill air injection port configuration used for accommodating the cyclone vent air with coal fines during startup, ramp-up and shutdown sequences and (ii) the successful implementation of the commercially proven Foster Wheeler coal burner in the precombustor.

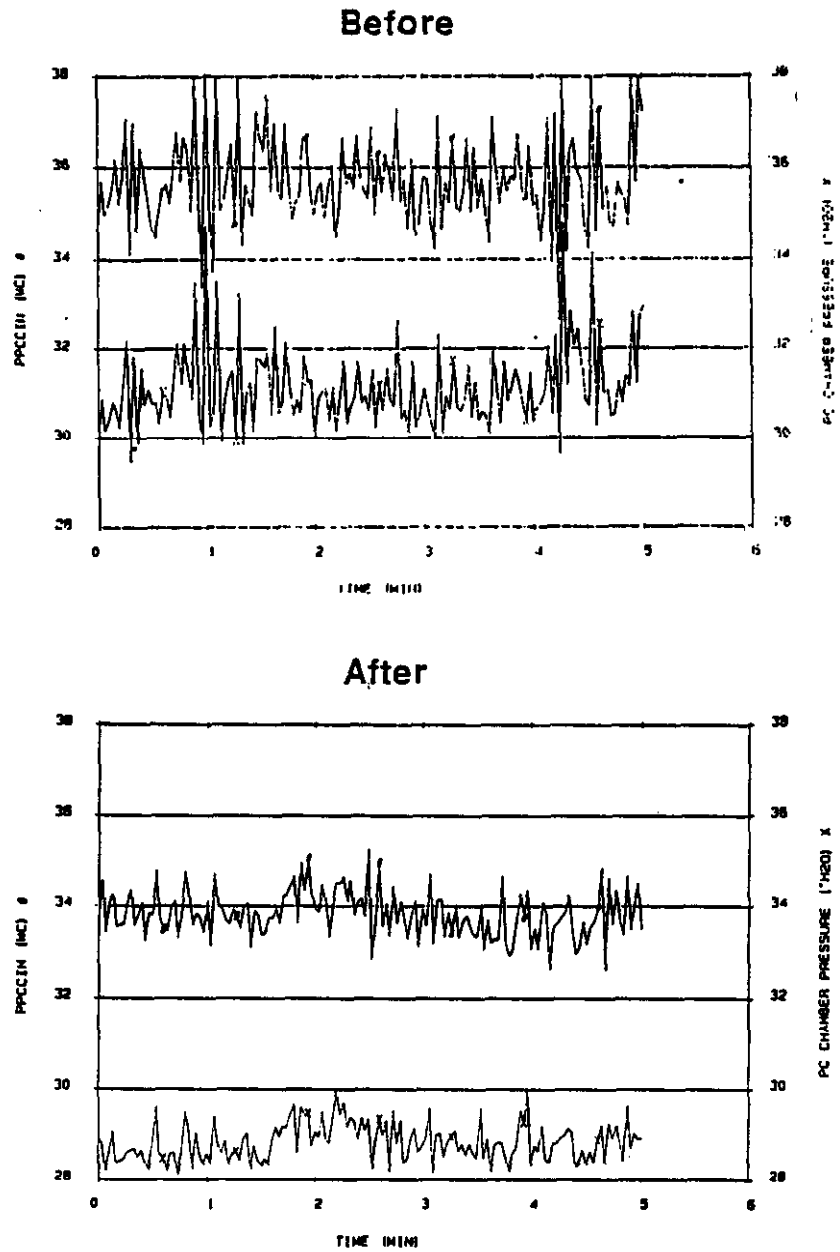


Figure 19 Flow Fluctuations Before and After Transport Line Modifications

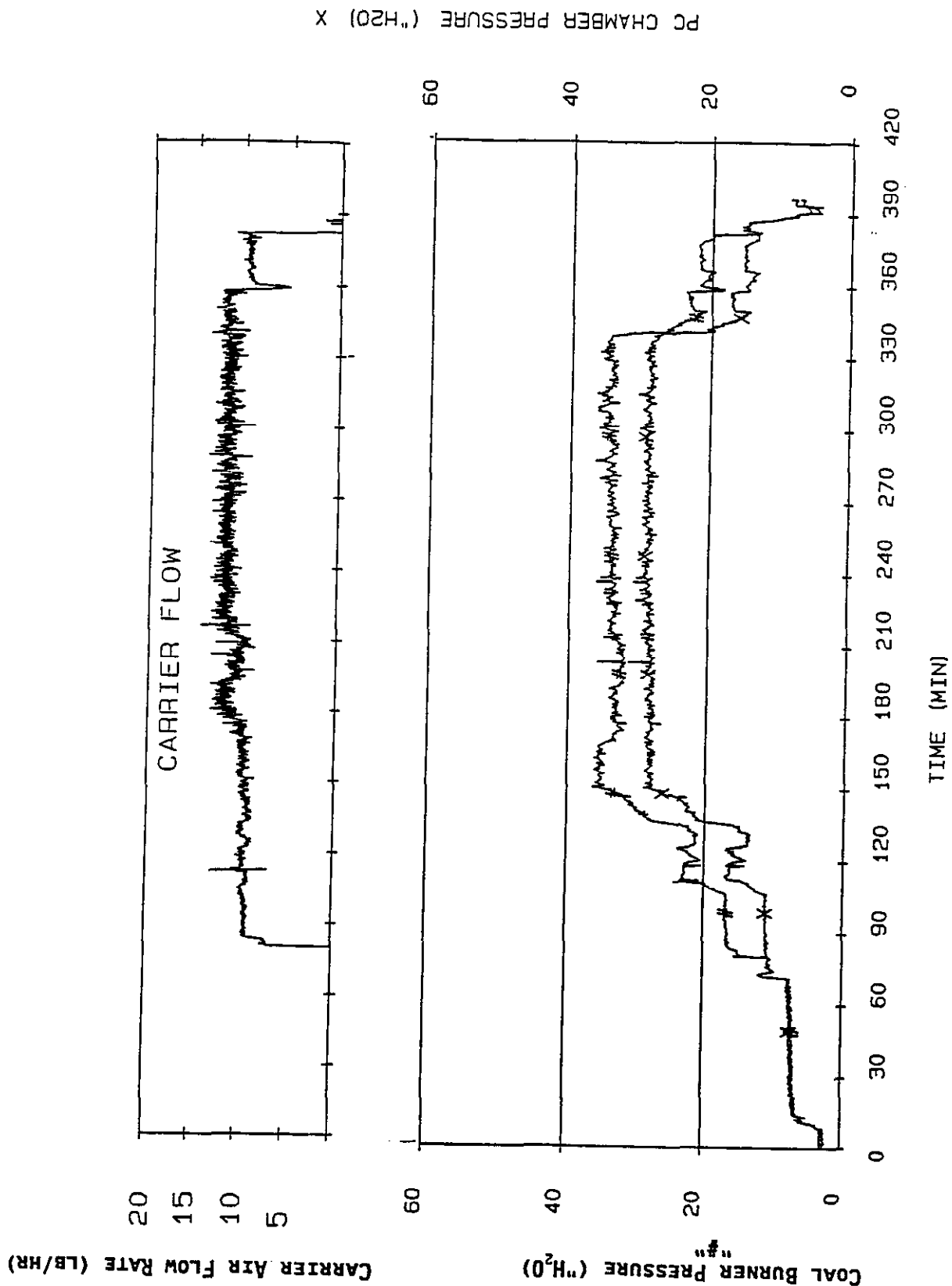


Figure 20 Stable Flow After Design Modifications

- o The one-tenth scale cold-flow model tests on the novel direct coal feed system proved the viability of the concept. The design verification tests on the first configuration of the one-third scale direct coal feed system in conjunction with the precombustor indicated undesirable coal accumulations in a few regions of the system. These results provided the valuable data and operational experience to improve the design, make the required hardware modifications and resume testing. The tests on the modified hardware validated its operation successfully through the entire startup, ramp-up and shutdown sequences, thereby giving sufficient confidence to scale it up by a factor of three to the Healy size. Cyclone efficiencies and pressure drops indicated that the blowdown cyclones could be designed using conventional cyclone design techniques.
- o The tests were repeatable and the data were reproducible.
- o The tests provided valuable operational data on startup, ramp-up and shut-down procedures, heat fluxes in various sections of the precombustor, pressures and pressure drops, saltation velocity diagnostics, etc.
- o By performing the design verification tests at TRW's Capistrano Test Site, the HCCP avoided the high cost and adverse schedule impact the project would have experienced without the benefit of such tests due to potential hardware modifications at Healy.

In general, the design verification tests provided the confidence and valuable data and procedures needed to finalize the Healy design.

Part 2: Project Status

1.0 Introduction

The Healy Clean Coal Project (HCCP) features the innovative integration of TRW's slagging combustion system with Joy Technologies' advanced flue gas desulfurization system. The integration of these technologies is expected to cost effectively result in low emissions of NO_x and SO_2 .

The HCCP is jointly funded by the Alaska Industrial Development and Export Authority (AIDEA) and the U.S. Department of Energy (DOE). The HCCP was selected by DOE in Round III of its Clean Coal Technology Program. AIDEA has assembled a team comprised of TRW Inc. (TRW), Joy Technologies, Inc. (Joy) and its European associate Niro Atomizer (Niro), Foster Wheeler Energy Corporation (FWEC), Golden Valley Electric Association Inc. (GVEA), Usibelli Mine, Inc. (UCM), and Stone & Webster Engineering Corporation (SWEC) to design, build, operate, and test the plant through

demonstration. The following provides a summary of the project status through July 1993.

2.0 Permitting

The following major permitting milestones have been completed:

- o The Prevention of Significant Deterioration (PSD) permit was issued by the Alaska Department of Environmental Conservation in March 1993.
- o A camera-based visibility monitoring program was completed in April 1993.
- o The Draft Environmental Impact Statement (EIS) was issued by DOE in November 1992. The final EIS is expected to be issued later this year.
- o Applications for other major permits were submitted and are expected to be approved after the Final EIS is completed.

3.0 Design/Engineering

Overall engineering and design is approximately 85% complete. All major equipment procurements were placed. The following identifies the status of activities for the major participants:

- AIDEA- AIDEA is the owner of the HCCP and provides overall project management
- GVEA- GVEA owns the existing Healy Unit No. 1 power plant which is immediately adjacent to the proposed HCCP. GVEA is providing design review for HCCP and will operate and maintain HCCP as well as purchase all electric power from HCCP. GVEA has obtained the Alaska Public Utilities Commission approval for the AIDEA/GVEA power purchase agreement. GVEA has also prepared the HCCP site to accommodate the HCCP construction.
- TRW- TRW is the slagging combustion system technology developer and supplier of the combustion system and auxiliary systems. TRW has completed the Phase 1 design activities including the Healy coal test burns at Cleveland, the cold flow modeling tests at Redondo Beach, and the DVT at San Juan Capistrano. TRW has signed a contract with AIDEA for the supply of the slagging combustion system, the coal feed system and the limestone feed system.
- FWEC- FWEC is under contract with AIDEA for the supply and erection of the boiler and its auxiliaries. TRW is also subcontracting the fabrication of the slagging

combustors to FWEC.

Joy- Joy is the technology developer and supplier of the flue gas desulfurization (FGD) system with reactivation and recycle of the fly ash. Joy has completed testing of the FGD and reactivation process at the Niro facility in Copenhagen. Joy has also completed the design of the FGD system for HCCP.

SWEC- SWEC has responsibilities for permitting, and for the balance of plant engineering, design, and procurement. All procurements were awarded including the turbine generator supply and erection contract to Sumitomo Corporation of America.

Vendor engineering and design are currently in progress, and are scheduled for completion by May 1, 1994.

4.0 Construction

Construction is currently scheduled to begin in Spring of 1994. Start of the demonstration test phase is scheduled to begin September 1996. Commercial operation is scheduled to begin after the demonstration test program.

5.0 Conclusions

The HCCP team participants look forward to the successful operation of the project and expect the project to demonstrate:

- o Advanced U.S. based clean coal technologies.
- o Economical, reliable, and environmentally acceptable commercial operation.
- o Emissions significantly below the current New Source Performance Standards limits.
- o Economical use of limestone as a sorbent material.

Session 6

Advanced Electric Power Generation Systems

Co-Chairs:

R. Daniel Brdar,

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U.S. Department of Energy

IGCC DEMONSTRATION PROJECT STATUS

COMBUSTION ENGINEERING IGCC REPOWERING PROJECT

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Abstract

This demonstration project was originally conceived as the repowering of an existing plant facility, the Lakeside Station in Springfield, Illinois. The Owner, City Water, Light and Power (CWL&P), has removed five of the original boilers and three of the original turbines. The buildings have had asbestos insulation removed and the interiors have been prepared for the construction of a single Integrated Gasification Combined Cycle (IGCC) process train that will generate a net output of 60 megawatts. The plant consists of a combined cycle (gas turbine, heat recovery steam generator, steam turbine) power train located in the existing buildings and a coal gasification system in a new building. The gasification system contains ABB CE's air-blown, entrained flow, two stage gasifier, an advanced hot gas desulfurization system by General Electric Environmental Services, Inc. and the necessary auxiliary systems. The plant is designed to produce a nominal 60 MW net output with an ambient air temperature of 95°F and a cooling water temperature of 89°F on either Natural Gas or Illinois No. 5 coal. Space has been provided for the future installation of a second combined cycle power train. After the completion of plant start up and commissioning, the project was to begin a five year demonstration period to establish the operability and commercial viability of this technology. The Project has completed Budget Period 2 which was to include the completion of the preliminary plant design and a $\pm 20\%$ estimate for the installation, start-up and commissioning of this turnkey facility. Due to site specific conditions, increased capital costs and the small power output of the facility, the estimate has exceeded what can be funded and the project will not continue at this site.

Combustion Engineering IGCC Repowering Project
IGCC Demonstration Project Status
Springfield, Illinois

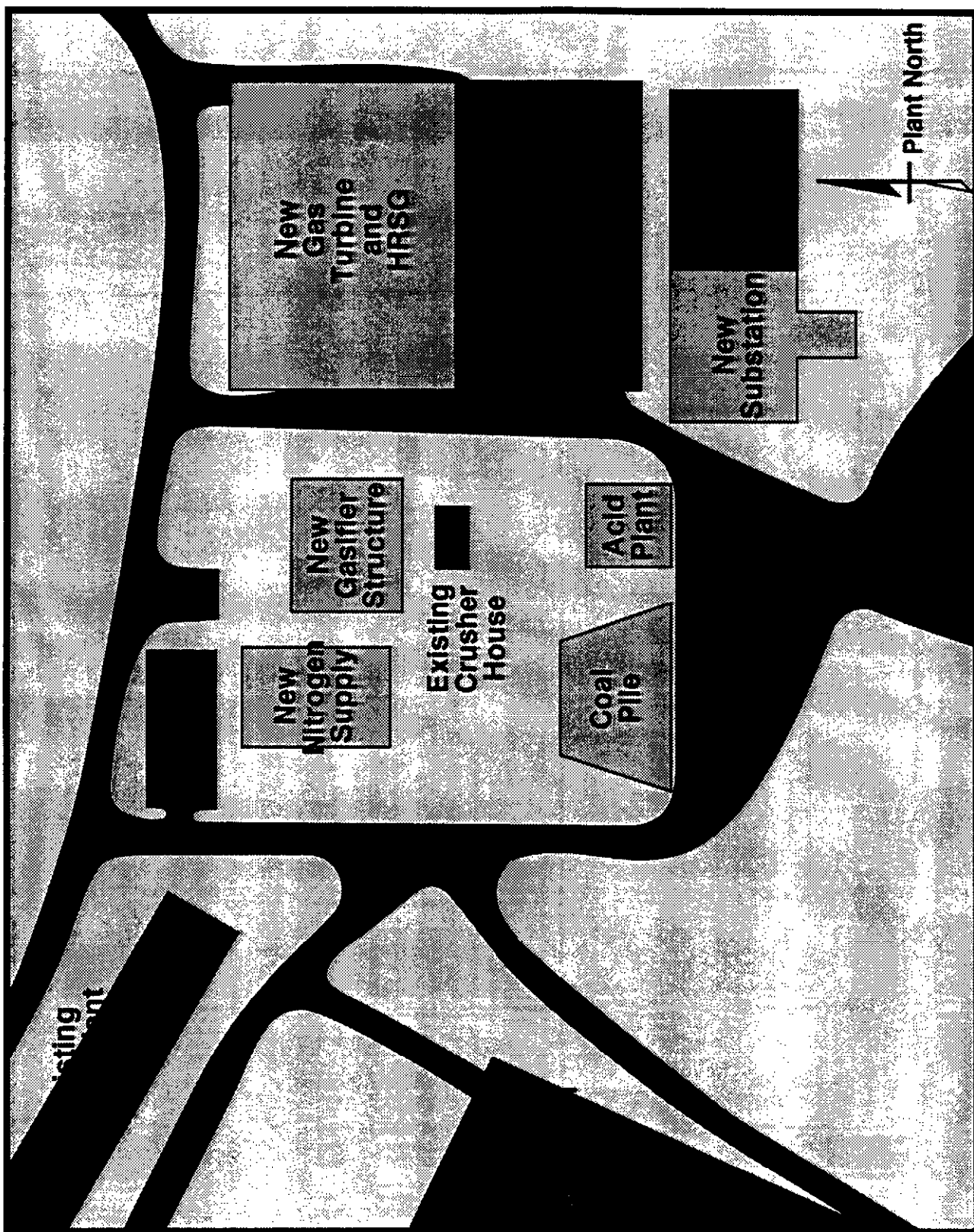
1.0 PROJECT STATUS

Combustion Engineering, Inc. (ABB CE) applied for and was awarded a cooperative agreement by the U.S. Department of Energy (DOE) under the Clean Coal Technology Program to build and operate a plant to demonstrate ABB CE's air blown coal gasification process in an IGCC application. For the demonstration project, an existing facility was to be repowered with new equipment. The concept is to use as much of the existing plant as possible to minimize the total cost. The site chosen for this project is City Water Light & Power's (CWL&P) existing Lakeside Station in Springfield, Illinois where it was initially believed that most of the boiler island could be refurbished and reused. Fifty percent of the project was funded by DOE and the balance split between ABB CE, CWL&P and the State of Illinois. The Project application was for \$270,100,000 to cover the total cost of designing, renovating and building the facility and demonstrating the technology for five years.

The Integrated Gasification Combined Cycle process train will generate a net output of 60 megawatts. The plant will consist of a combined cycle (gas turbine, heat recovery steam generator (HRSG), steam turbine) power train located in the existing buildings and a coal gasification system in a new building. Figure 1 is a plot plan of the site with the new equipment layout. The gasification system contains ABB CE's air-blown, entrained flow, two stage gasifier, an advanced hot gas desulfurization system by General Electric Environmental Services, Inc. and the necessary auxiliary systems. The plant is designed to produce a nominal 60 MW net output with an ambient air temperature of 95°F and a cooling water temperature of 89°F. Figure 2 is a flow schematic of the gasification process for this project.

Under the terms of the DOE cooperative agreement, the project is divided into five budget periods. Budget Period 1 was conceptual engineering, analysis and planning. During this budget period, the plant definition was to be established and basic engineering was initiated. This budget period was completed in December of 1991. Budget Period 2 started January 1992 and runs through September 1993. Budget Period 2 included the completion of the Preliminary Plant Design, preparing a $\pm 20\%$ cost estimate of the Preliminary Design and obtaining the necessary Air Emissions Permits. Budget Periods 3 and 4 cover final engineering, procurement, construction, start-up and commissioning while Budget Period 5 is the five year demonstration period. At the end of Budget Period 5, the gasification plant would be removed if the customer did not wish to take possession.

ABB Lummus Crest Inc. (LCI) was retained to produce preliminary designs for the balance of plant, produce the preliminary plant estimate and assist in obtaining the Air Emissions Permits. In June 1992, ABB CE and LCI issued a budget estimate for Budget Periods 3 and 4 of \$318,400,000. This estimate was developed using a factored equipment methodology and was independent of the Process Flow Diagrams, Piping & Instrumentation Diagrams and Equipment Specifications being developed during Budget Period 2. The engineering definition was not



* NOT TO SCALE

Figure 1

ABB C-E IGCC Flow Diagram

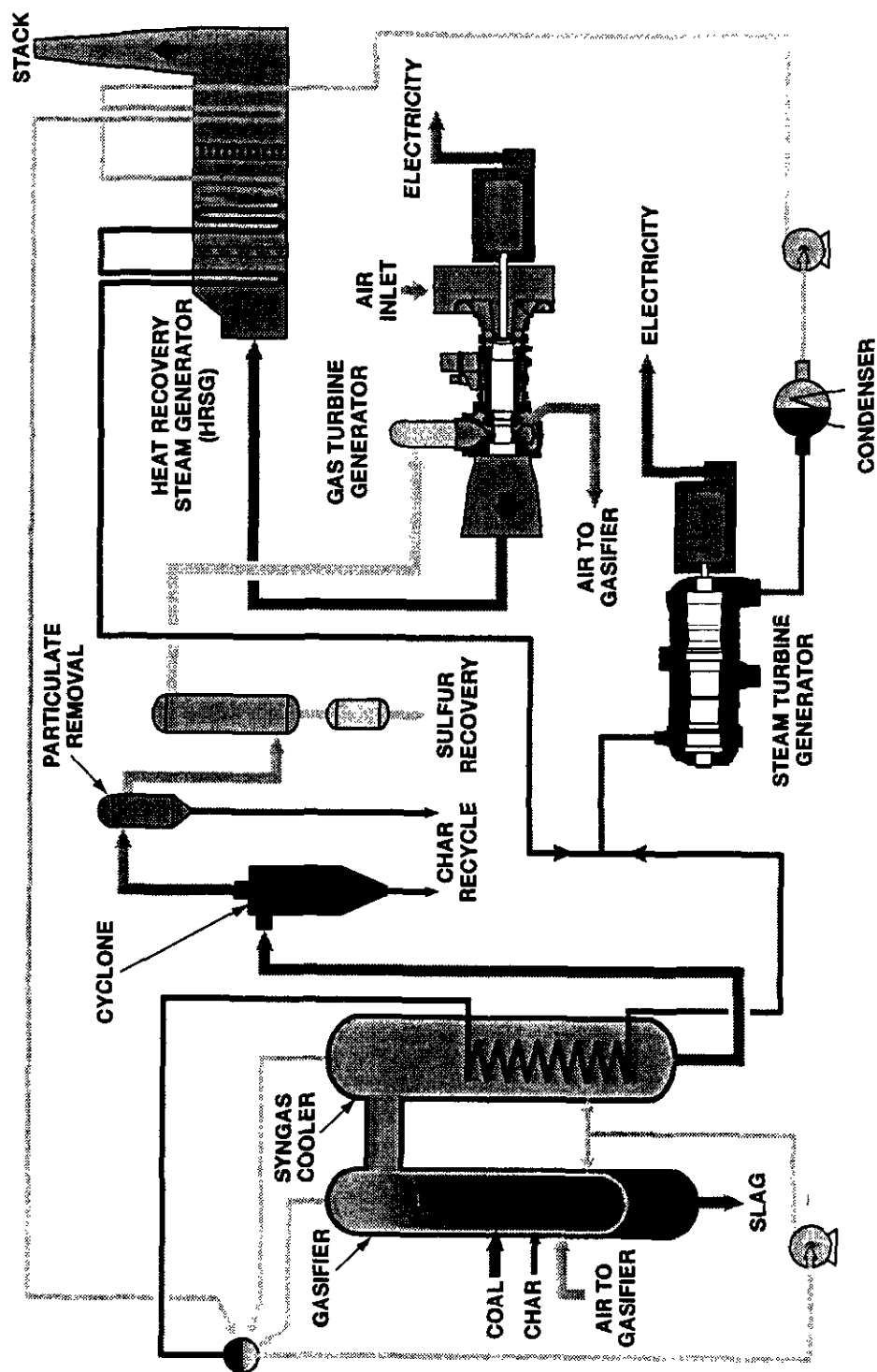


Figure 2

complete. There were no specifications or quotations obtained from vendors for this initial budget estimate and therefore the margin for error was high. This estimate was considered excessively high by all of the project participants.

During the second half of 1992, ABB Lummus Crest Inc. and ABB CE produced Process Flow Diagrams, Piping and Instrumentation Diagrams, Equipment Specifications and Quotations for almost all of the major equipment.

At the end of 1992, a decision was made by the Fundees to obtain an independent assessment of the project estimate. Duke Engineering and Services(DE&S) was retained to assess the design and produce a new estimate. DE&S used the design information generated by ABB Lummus Crest Inc. as a starting point for developing a total plant design. DE&S contracted for a labor study of the Springfield, Illinois area to determine actual labor rates. DE&S utilized their own data base for equipment, construction and operating costs. During this effort, several cost reduction efforts were initiated by ABB CE and DE&S. The plant was originally designed to maximize efficiency rather than minimizing cost per kilowatt of generation. The time constraints prevented performing a complete cost benefit analysis but some large systems were redesigned to reduce cost.

In April 1993, DE&S and ABB CE formally issued the new estimate of \$274,400,000 for the Budget Periods 3 and 4. This is a complete turnkey plant estimate including Start-up and Commissioning. The estimate for Budget Period 5 is \$133,200,000. The total, \$407,600,000, is considered too high and the funding participants have decided not to continue funding the project in its present structure.

The high cost of this project is the result of many factors. The estimate developed for this project should not be used to compare air blown gasification to other gasification technologies. There are three primary factors which contribute to the high cost of this project when it is compared to other DOE IGCC projects. The small generating capacity of this facility, the lack of reusable equipment in the Lakeside location and site specific requirements.

The small size of this facility, 60 MW net output, results in a very high cost per kilowatt because some of the fixed costs on a development project are independent of size. Engineering costs are approximately \$500 per net kilowatt. If the plant were five to ten times larger, the total cost of Engineering would essentially be unchanged. Since larger gasification projects generate significantly more megawatts, the cost per megawatt is substantially lower due to economies of scale. However, this does not mean that this is the wrong size for this plant. This is to be a demonstration project and the purpose is to determine the commercial feasibility and reliability of the technology. Given that this is a first of a kind plant, it is purposely kept small to minimize total capital expenditures and possible rework costs. It was not meant to have the optimum cost per kilowatt or compete with other gasification technology projects which are larger and second and/or third generation designs.

When the initial project estimate was conceived, it was to be a repowering project funded under the Clean Coal Program. Some of the equipment that was assumed to be usable, the steam turbine and generators, the steam turbine crane, turbine hall, feedwater treatment system and

electrical transmission equipment was later found to be inadequate or limited in capacity. The customer, CWL&P, also imposed requirements that the gasification plant be independent of the existing boilers. Since the initial estimate was based on conceptual engineering, no definitive project scope had been developed or included in the contract, and thus, no adjustments were made which provided for an increased scope in the project funding. It was assumed that a typical owner's scope of supply would be provided. This assumption was incorrect. Major items such as rebuilding the natural gas pipeline for 1.5 miles and rebuilding the railroad spur added significant cost. There were no significant changes in the process equipment but there were substantial changes in the layout and scope of equipment. A layout of the gas turbine/heat recovery steam generator train was required that used both buildings and provided space for a symmetrical future gas turbine/heat recovery steam train. This required approximately 100 feet of high temperature (1000°F) ductwork to connect the gas turbine to the HRSG. The only existing systems that were used in the final design were the water supply tunnels and the waste water treatment facility. Building a complete new plant next to the existing buildings would be less expensive due to the avoidance of the building renovation costs. Additionally there was concern about construction activities damaging the City's public water supply pipelines which originate in this same building. Due to the possible consequences resulting from stopping the only water supply to the Capitol of Illinois and from the structural instability of the building while it was being renovated, DE&S was unable to obtain a quotation for insurance from any major carrier in the time that was available. Relocating and possible rebuilding of these water pipelines has been included in the project estimate.

The methodology used by DE&S and ABB CE to develop the operating budget for Budget Period 5 took into consideration the fact that the gasification facility would be a stand alone facility that would operate over the five year demonstration period at specific operating levels.

Being a stand alone facility, it was assumed that the unit would be staffed accordingly. It would be self-supportive and none of the spare parts, process chemicals, fuel, rolling stock, etc., purchased for the gasification facility would be shared with the existing Lakeside Station.

Several other factors were considered in developing the operating criteria and the resultant operating budget. First, DE&S and ABB CE utilized historical operating experience with conventional gas fired turbines, circulating fluidized bed boilers and atmospheric coal gasification technologies to develop estimated annual capacity factors. Second, vendor assistance in understanding operating characteristics for the proposed equipment was solicited; ie., char recycle system, hot gas desulfurization system and sulfuric acid production system.

Once the predicted operating criteria were finalized, operations and maintenance costs were developed for the five year operating budget plus a 20 month commissioning period. The O&M estimate included costs for labor, spare parts and consumables, fuel, process chemicals, waste disposal, transportation costs, nitrogen, auxiliary power costs and subcontract labor costs.

2.0 BACKGROUND

Combustion Engineering, Inc. has been involved in developing a coal gasification process to produce clean fuel gas from coal for power generation for over two decades. ABB CE has chosen to place the emphasis on developing a process for electric power generation by selecting an air blown, entrained-flow gasifier which operates in many ways similar to pulverized coal-fired boilers used by the electric power industry for many years.

In the early 1970's, under joint sponsorship of the U.S. Government and Consolidated Edison Company of New York, ABB CE evaluated various types of gasification schemes for electric power generation on terms of economic, technological and environmental considerations. The study recommended that a two-stage, entrained flow, low-Btu, slagging bottom gasification process be developed for utility power generation applications.

In 1974, ABB CE initiated a program under the joint sponsorship of the United States Energy Research and Development Administration (predecessor of the Department of Energy), the Electric Power Research Institute (EPRI) and ABB CE to develop a two-stage, atmospheric pressure, entrained-flow coal gasification system.

The process was developed in a Process Development Unit (PDU) located in Windsor, Ct. The unit gasified Pittsburgh seam coal at a nominal firing rate of 120 tons per day (TPD). The gas making operation at the PDU began in June 1978 and continued over a period of three years. The objectives of the program were to produce clean, low-Btu gas from coal and to provide the design information for scale-up to commercial-size plants. These objectives were met.

After completion of the PDU program, ABB CE directed its efforts to data analysis and the development of a pressurized version of the gasification process. Analysis of the PDU data has provided the basis for developing, refining and checking mathematical process models and design procedures. The engineering analysis performed has significantly enhanced ABB CE's ability to design multistage, entrained-flow gasifiers to allow more flexibility and to better predict performance.

ABB CE's continued development of its gasification technology led to the introduction of a pressurized version of its reactor. In the early 1980's, the design for a 2-TPD pressurized pilot plant was developed. This pilot plant was built in 1983 and ran until 1985. A second 2-TPD pilot with design improvements was built in 1985 and operated successfully.

In 1990, ABB CE began participation in the coal gasification combined cycle repowering project that would provide a nominal 60 MW of electricity to City Water, Light & Power in Springfield, Illinois.

3.0 EQUIPMENT DESCRIPTION

Plant Layout

Like most repowering projects, there is not enough room left for new equipment to allow optimal layout. The gasification unit is in a separate building from the combined cycle equipment due to the lack of room in the existing building. A conceptual layout for the gasifier and auxiliaries is attached in Figure 3. The railroad line into the plant will be refurbished to allow heavy components to be transported into the site. After construction, the line will be removed to allow continued operation of the coal yard. The roads through the site must remain open during construction so that coal trucks delivering to the adjacent power facility are not obstructed.

Coal Storage System

Illinois No.5 coal is washed at the mine and delivered to the site in trucks. The trucks dump into open-top drive-over hoppers, with coal dropping into the receiving hopper. From the receiving hoppers, coal is transported by conveyor to the enlarged storage pile. This storage pile serves both the IGCC project and the existing Lakeside units. A new reclamation hopper beneath the coal pile reclaims coal from the storage pile and conveys it on a conveyor to the gasifier building. The reclaim hopper receives material by gravity after it has passed through a grizzly and a dust tight coal valve. The coal is transferred to the raw coal storage bunker in the gasifier building. The coal handling system for the existing Lakeside units remains unchanged and will be available throughout the construction period.

IGCC Coal Pulverizing System

The coal fed to the gasifier is pulverized in the pulverizer, while air, heated to 500°F, dries the coal to approximately 3 percent moisture and heats the coal to between 200 and 250°F. The coal is air classified by size in the pulverizer and pneumatically transported to the pulverized coal baghouse. In the baghouse, the coal is separated from the carrier air and the coal flows by gravity into the coal receiving bin. The carrier air, cleaned of particulate matter in the baghouse, is released through the coal vent stack.

Raw Coal Storage Bunker

The Raw Coal Storage Bunker will store enough coal for the operation of the gasifier for 24 hours. The bunker will feed the coal through a slide gate shut off valve and connecting pipe to the coal feeder. The Raw Coal Storage Bunker is sized to hold 1,200,000 pounds of coal.

Raw Coal Feeder/Pulverizer Mill

The raw coal feeder meters the flow of coal to the pulverizing mill. It is a volumetric feeder at the outlet of the raw coal storage bin. The coal pulverizer mill grinds the coal to a fineness that can be transported pneumatically and combusted in the gasifier. It is located below the raw coal feeder.

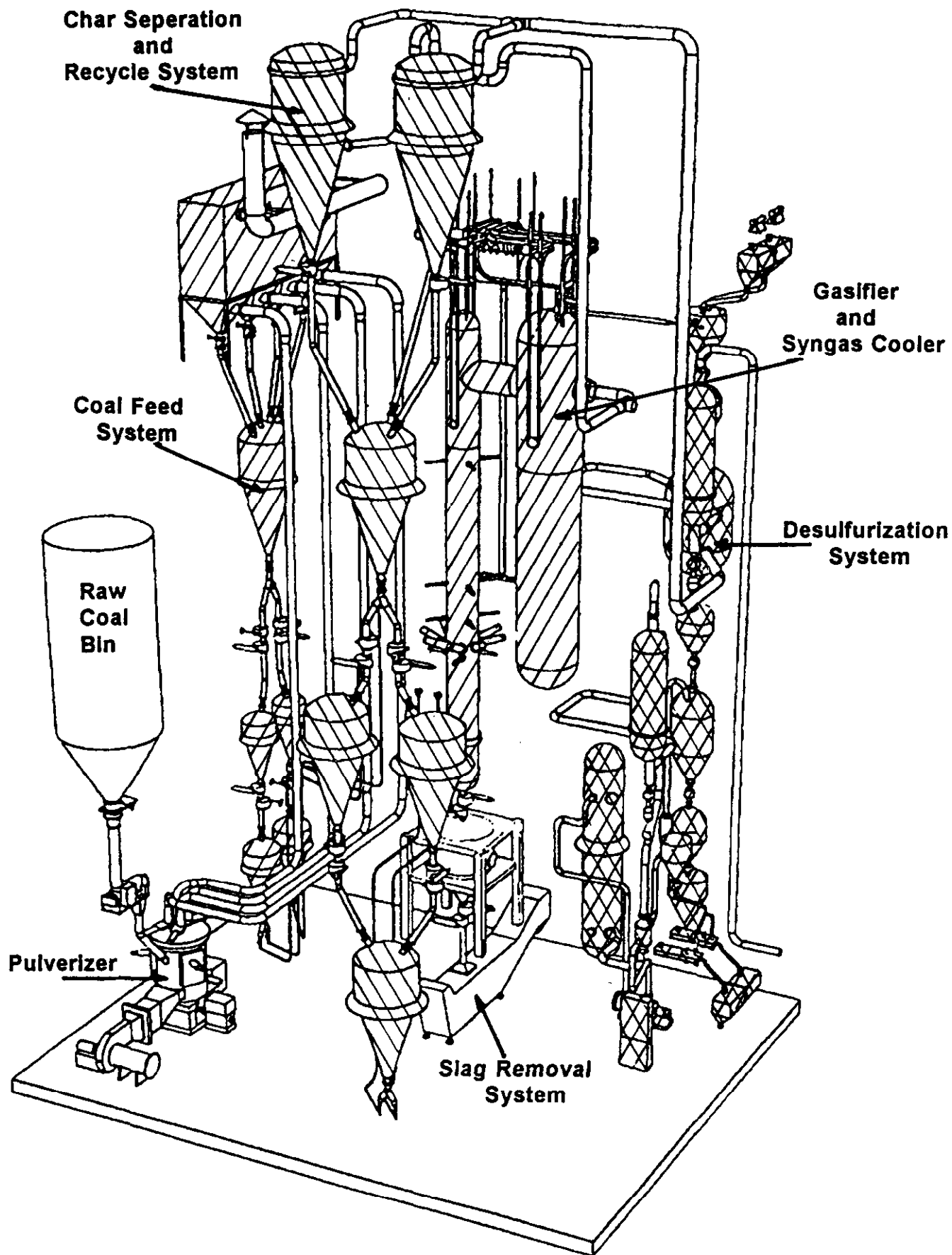


Figure 3

Pulverized Coal Baghouse

The pulverized coal is entrained in the air leaving the pulverizer and is transported through four individual pipes to the pulverized coal baghouse. The pulverized coal baghouse separates the transport air from the pulverized coal for storage in the coal receiving bin.

Pulverized Coal Receiving Bin

The pulverized coal continuously flows by gravity to the pulverized coal receiving bin. The receiving bin stores the pulverized coal for the intermittent feeding of the lockhoppers

Pulverized Coal Lockhoppers and Feed Bin

There are four pairs of coal handling valves which control the flow of pulverized coal into and out of each of the two lockhoppers. The pair of valves at the inlet of each lockhopper isolate the lockhopper from the receiving bin while the lockhopper is pressurized. The pair of valves at the outlet of the lockhopper isolate the lockhopper from the pulverized coal feed bin while the lockhoppers are depressurized and coal is flowing from the receiving bin into the lockhopper.

Pulverized Coal Flow Control Valves

The gasifier has three separate levels where the pulverized coal can be injected for combustion. Each level must be controlled separately. The pulverized coal flow control valves meter the flow of coal from the feed bin to the pickup Tee's and control the firing rate of each burner level in the Gasifier.

Gasifier/Heat Exchanger/Steam Drum

The gasifier and syngas cooler are utilized to produce a pressurized low-btu gas (LBG) or "syngas" stream which also contains char and H_2S . Pulverized coal is delivered and combusted in a deficiency of air. Gasification occurs in an entrained reactor. Sensible energy is removed from the gas in a heat exchanger called the syngas cooler. The gas exits the system for char removal and desulfurization. Coal ash is fused and tapped from the bottom of the gasifier as molten slag. All streams to and from the gasifier are pressurized.

Product gas leaves the gasifier and passes through a crossover and enters the syngas cooler. The bounding walls of the gasifier, crossover and syngas cooler are water cooled. The gasifier and syngas cooler are vertically oriented while the crossover is horizontal. Convective superheat surface is located in the syngas cooler. The heat transfer surface arrangement is configured to yield an outlet temperature over the operating load range which is within the limits imposed by the hot gas desulfurization system. Steam that is generated and superheated is integrated into the combined cycle.

The gasifier unit is a fusion welded, eight sided water walled pressure vessel. It consists of multiple stages for air, steam, coal and char introduction into the gasifier. The combustion zone is the lower section of the gasifier and the reduction zone is the upper section of the gasifier.

In the combustor, coal and recycled char are burned with almost all of the combustion air to form a hot gas to start the gasification reactions and melt the ash in the coal and char. In the oxygen deficient reductor, the rest of the coal reacts with CO₂ and water vapor to generate a synthetic gas consisting primarily of N₂, CO, H₂, water and char. The char consists of unreacted carbon, ash and trace metals from the coal. Collecting the char after it exits the gasifier and reinjecting it into the gasifier provides for complete burnout of all carbon in the fuel, thereby enhancing the efficiency of the process.

All surfaces exposed to gas from the slag floor to the outlet of the crossover are studded and covered with refractory. This includes the slag tap, waterwalls and all water cooled nozzles which penetrate into the gas pass. The product gas flows from the gasifier vessel at a temperature of approximately 2000°F, to the heat exchanger where it is cooled to approximately 1000°F before being piped to the hot gas desulfurization system.

The syngas cooler is comprised of a pressure vessel and an internal water cooled gas pass which contains convective heat exchanger surface. The arrangement has two vertical passes. Gas enters horizontally from the crossover and is directed into a downward channel. At the bottom of the channel it is redirected upward into the pass containing the convective surface. The downward gas pass and the upflow pass share a common division wall. Gas then enters a horizontal transition section which is coupled to a removable pressure vessel nozzle.

Steam is generated in the waterwalls of the gasifier vessel and the heat exchanger and superheated in the heat exchanger. Separation of the steam and water occurs in the steam drum. The waterwalls are contained inside of the gasifier and heat exchanger pressure vessels. The superheater elements are located in the gas path of the heat exchanger. Steam leaving the superheater is piped to the turbine for the generation of electric power. The annulus area between the gas pass and the ID of the pressure vessel is pressurized with steam at a pressure slightly higher than the gas pass. This maintains a blanket of non-corrosive gases on the internal walls of the pressure vessels to prevent possible corrosion by the product gas. A water seal accommodates the differential movements and provides for a gas tight seal between the annulus area and the gas pass. It allows for pressure equalization between the annulus and the gas pass during transients. Air for combustion of the coal is taken from the gas turbine compressor section. A booster compressor raises the pressure to that needed for the gasifier burners.

Slag Tank/Slag Grinder/Slag Grinder Vessel

The high temperatures in the combustion zone of the gasifier melt the slag which flows down the refractory covered waterwalls of the gasifier to the slag tap. Molten slag drops from the gasifier slag tap into a water filled tank located at the bottom of the gasifier vessel bolted to the bottom flange connection of the gasifier vessel. An inner cylindrical and conical shroud is used to funnel the slag to the grinder. The grinder is a motor driven shear shredder located inside the slag grinder pressure vessel. An auxiliary heat exchanger maintains the slag tank water temperature. Located beneath the gasifier vessel is the slag lockhopper with the associated double valving at the inlet and outlet.

Slag Lockhopper/Transport Conveyor System

The slag and water are discharged through a pair of valves to a lockhopper. The slag and water

then flow through a second set of valves into a submerged scraper conveyor for dewatering and transport to the load out belt conveyor. The load out belt conveyor carries the slag to a three sided concrete ash storage bin. Ash will be loaded from the bin into trucks by a front end loader for disposal offsite.

Slag Water Recycling System

The water processing portion of this system consists of collecting and recycling as much of the slag quench and the slag lockhopper water as possible. This recycling will reduce the load on the industrial wastewater treatment facility and minimize the makeup water requirements. The water is sent to a new concrete lined settling basin located just outside the gasifier building.

Char Cyclone, Seal Bin and Char Removal Bagfilters

Product gas leaves the heat exchanger and flows through the char cyclone and then to the char removal bagfilters. The char removed in the cyclone flows by gravity via the char seal bin to the char receiving bin. Char collected in the bagfilters discharges by gravity to the char receiving bin. The baghouse is cleaned by pulsing the bags with low pressure steam. The filtered product gas is piped to the hot gas desulfurization system. The char cyclone and char removal bagfilters operate at approximately 1000 °F and 300 psi. The bagfilter is designed to use Nextel ceramic bags at present. Sintered metal and ceramic crossflow filters are also being considered.

Char Receiving Bin and Char Lockhoppers

The char is collected in the char receiving bin and feeds out intermittently to two char lockhoppers. The flow is controlled into and out of each lockhopper by pairs of char sealing valves. The char lockhoppers are pressurized with steam to a pressure higher than the operating pressure of the gasifier and intermittently discharge to the char feed bin by gravity. During start up and shut down, the lockhoppers and feed bin are pressurized using nitrogen. Inside of each lockhopper, receiving bin and feed bin, there are fluidizing devices to keep the char from compacting and keep the char flowing from vessel to vessel.

Char Feed Bin and Transport System

The char feed bin continuously feeds char through the flow control valves at a pressure high enough to overcome the gasifier operating pressure. The char is fed through either of the two flow control valves to char pickup Tee's. When the unit is operating, transport steam is introduced to carry the char to stream splitters where the char flow is divided and piped to the char burners. During start up, nitrogen is the transport medium. The char is reinjected into the gasifier at either or both char burner levels to finish volatilization of the char particles. There will be no waste stream other than slag during normal operation.

Hot Gas Desulfurization System

The syngas leaving the char removal baghouse has been cleaned of particulate matter. The syngas is expected to consist primarily of N₂, CO, H₂ and water with low concentrations of H₂S, COS, CS₂ and chlorides. The sulfur and chlorine compounds must be removed prior to

combustion of the syngas in the gas turbine. To maintain the overall thermal cycle efficiency, the gas is not cooled before entering the gas desulfurization system. The syngas enters the absorber and flows countercurrent to a moving bed of zinc titanate (ZnTi) pellets. The absorber is a high pressure and temperature vessel filled with zinc titanate sorbent material. The gas enters the side of the absorber in the lower section and flows upward causing the gas to come in direct contact with the zinc titanate and the sulfur in the gas combines with the sorbent. The sulfur compounds (mainly H_2S , COS and CS_2) in the gas will react with the sorbent. Following sulfur adsorption, sorbent material is conveyed to a lockhopper and then to regeneration. In the regenerator, the metal oxide is regenerated and SO_2 produced. Regenerated sorbent, purged of SO_2 is recycled to the absorber lockhopper. The supply of regenerated metal oxide is slightly depleted during regeneration and handling. Fine particles of sorbent entrained in the cleaned gas stream are captured in a downstream high efficiency cyclone. The ZnTi fines, because of their high zinc content, are recycled to the sorbent supplier and will not be a waste byproduct. Chlorides are removed from the gas upstream of the absorber. Nahcolite is injected into the syngas after the char removal baghouse. The Nahcolite converts the chlorine into NaCl which is a solid and can be filtered out and disposed of offsite. Heat generated in the regeneration process will be used to generate steam which is piped back to the gasifier steam drum. The clean syngas is piped to the gas turbine for combustion. The SO_2 produced during sorbent regeneration is piped to the sulfuric acid production plant.

When a set pressure drop has been reached in the absorber on the gas side, a portion of the absorber bin's inventory is discharged through a lockhopper to the sorbent regenerator. At atmospheric pressure and under controlled solids flow rates, temperatures, air quantities and locations, the sorbent is regenerated by oxidation, producing an SO_2 -rich gas which is cooled and sent to an acid plant for conversion to sulfuric acid. With the regeneration of sorbent completed, the sorbent is discharged from the bottom of the regenerator, screened and sent to a bucket elevator. The elevator carries the sorbent back to the top of the absorber where it is introduced back into the absorber feed bin. In this way the freshest sorbent is in contact with the cleanest gas to get the best sulfur removal. The cleaned gas leaves the absorber and any entrained particles are removed as the gas goes through the secondary cyclone.

Sulfuric Acid Recovery System

The gas stream leaving the regenerator of the hot gas desulfurization system consists primarily of SO_2 and nitrogen. The gas stream is humidified, cooled and dried so that the moisture remaining in the gas is equivalent to the water content of the product acid. The gas is heated in a recuperative heat exchanger against exiting gases and passed through a four stage catalyst bed, which converts 99+ percent of the SO_2 to sulfur trioxide (SO_3). The bed will be periodically cleaned and replaced as necessary. The mixture is further cooled in another recuperative heat exchanger and passed through either one or two contact absorption towers, where the SO_3 is absorbed into 98 percent H_2SO_4 . The acid is then transferred to an acid storage tank. The acid is of commercial grade quality and represents a marketable byproduct rather than a waste stream. The sulfuric acid production plant is free standing and separate from the gasifier building or from the Lakeside Station building.

Gas Turbine

After particulate and sulfur removal, the syngas is fired in the combustion turbine. The turbine is a GE Frame 6 model. The turbine will have the capability to be fired with natural gas if the gasifier is out of service. The gas turbine is located in the renovated Lakeside Station building. The exhaust from the gas turbine is approximately 1030°F at full load. This exhaust gas is routed to the heat recovery steam generator. The air for the combustion of the coal and char in the gasifier is extracted from the compressor section of the gas turbine. A booster compressor controls the amount of air extracted and further increases the pressure of the combustion air. The air is cooled after extraction from the gas turbine. The heat is captured in a heat exchanger and is used to generate steam for the steam turbine cycle.

Heat Recovery Steam Generator

The heat recovery steam generator (HRSG) takes the hot exhaust gas from the gas turbine and recovers the heat to generate steam. The HRSG is able to fire natural gas to supplement the gas turbine output during high ambient temperature conditions and when the gasifier is off line and the gas turbine is firing natural gas only. The HRSG is located in the Lakeside Station building. The exhaust gas leaving the HRSG is ducted up and over the roof to a new stack. The HRSG will be delivered in preassembled modules with final assembly being performed in the field. The inlet ducting is a prefabricated and pre-insulated construction.

Steam Turbine

Steam from the HRSG plus steam from the waterwalls of the gasifier and various gasifier heat exchangers is piped to the steam turbine. The steam turbine will operate with steam at 1265 psia and 950°F at the throttle inlet valve. The steam turbine is connected to a synchronous generator that will produce 37 megawatts. The steam is exhausted from the turbine down into the steam condenser. The condenser cools the steam back to condensate and returns the water back into the cycle. The cooling water for the main condenser comes from the lake water circulation system.

Nitrogen Supply System

The Nitrogen Supply System (NSS) Provides N₂ which is used to pressurize, fluidize and displace coal in the lockhoppers and feed bin. It is also used as the conveying medium in the coal transport lines. Nitrogen is the purge gas in the coal feed vessels, the gasifier, heat exchanger, char feed and recycle vessels, hot gas desulfurization, gas turbine, flare and all interconnecting piping. Purging is necessary to prevent explosive mixtures from accumulating in the gasifier area. Nitrogen has been chosen as the purge gas because it is the least expensive inert gas that can be provided in the required quantities.

Plant Control System

The control and information system for the plant is a Distributive Control System (DCS) with a new control room located adjacent to the existing control room. The DCS consists of

controller, console, data processor and high density I/O subsystems linked together by a data highway. Various plant maintenance functions can also be tracked and stored so that the system can inform staff of required equipment maintenance. All functions of the plant performance computer are accessible through the DCS control room console workstations or through the DCS engineer's console.

Demineralized Water System

The demineralized water system consists of three 40 gpm trains. Potable water is used as the demineralized water system supply. Continuous makeup to the condenser hotwell is supplied by the demineralizer water system at the normal system flow rate. Demineralized water is also supplied to the chemical injection package, the nitrogen supply system and is an emergency source of cooling for the gasifier cooling water heat exchanger. A 25,000 gallon capacity demineralized water storage tank is provided. Sulfuric acid used for system regeneration is obtained from the sulfuric acid storage tank located near the sulfuric acid plant. Caustic used for system regeneration is supplied by a 3000 gallon storage tank.

Feedwater Chemical Injection System

Boiler feedwater quality control is provided by a vendor supplied chemical injection package. The system conceptual design utilizes phosphate, morpholine and hydrazine additives.

Circulating Water

Circulation water will be taken from the intake tunnel by two motor driven pumps. A flow of 50,400 gpm will be sent to the surface condenser. The remaining flow will be diverted to the slag water makeup pond and the closed loop cooling system.

Potable Water System

The potable water system distributes potable quality water to the existing building, the new gasifier building and the surrounding areas. Potable water is supplied to a system header by the existing CWL&P site potable water system. No new makeup pump or storage capacities are employed.

4.0 DESIGN CONSIDERATIONS

Steam Cycle

The steam cycle for the Integrated Gasification Combined Cycle plant was modeled on a computer program developed for this project. A simplified diagram of this cycle is shown in Figure 4. The steam turbine is designed for steam inlet conditions of 1250 psia, 950°F. Full load steam turbine output is approximately 37 MW gross. There are two main steam generating systems in the cycle. The HRSG generates steam by recovering heat from the gas turbine exhaust. In parallel with the HRSG, the gasifier recovers heat from the gasification process. The heat is recovered in the gasifier system in the gasifier waterwalls, the syngas cooler and the desulfurization system evaporator bank. The HRSG generates approximately 60 percent of the steam in the cycle. The gasifier/heat exchanger generates the remainder.

The steam leaving the turbine enters a deaerating condenser system. The condensate leaving the condenser system then enters a low pressure feedwater heater. The feedwater leaves the feedwater heater before entering the HRSG at a temperature high enough to avoid acid dew point condensation problems. Approximately 90 percent of the economizer heat absorption is performed in the HRSG while the remaining 10 percent is accomplished in the booster compressor air cooler which is in a circuit parallel with the HRSG. The booster compressor air cooler is used to maintain the air temperature leaving the booster air compressor at 600°F. The majority of the feedwater leaving the economizer is biased between the HRSG steam drum and the gasifier steam drum. The water leaving the booster compressor air cooler is fed to the gasifier steam drum.

The water in the HRSG drum circulates through the evaporator banks in the HRSG and back to the drum through natural convection. The steam/water mixture is separated in the drum. The separated water is combined with the entering feedwater and then feeds the evaporator banks. The separated steam feeds the superheater circuit where it is heated from saturation temperature to 950°F. The HRSG steam outlet temperature is controlled by desuperheating spray water. The HRSG also has auxiliary natural gas fired burners for additional steam generation when required.

The water which feeds the gasifier steam drum is combined with recirculating water and flows through the evaporator circuits in the gasifier and hot gas desulfurization system evaporator and returns to the drum through natural convection. The steam/water mixture is separated in the drum. The separated steam feeds the superheater circuit where it is heated from saturation temperature to 950°F. The gasifier steam temperature control is provided by desuperheating spray water.

Gas Turbine Cycle

For a given gas turbine operating condition, a reduction in gasifier air temperature causes changes to the gasifier operating requirements. The gas turbine still requires the same amount of energy (sensible plus chemical) in the LBG fuel stream to provide the required turbine inlet temperature. If the air feed stream is at a lower temperature, the amount of coal fired in the

Integrated Steam Cycle

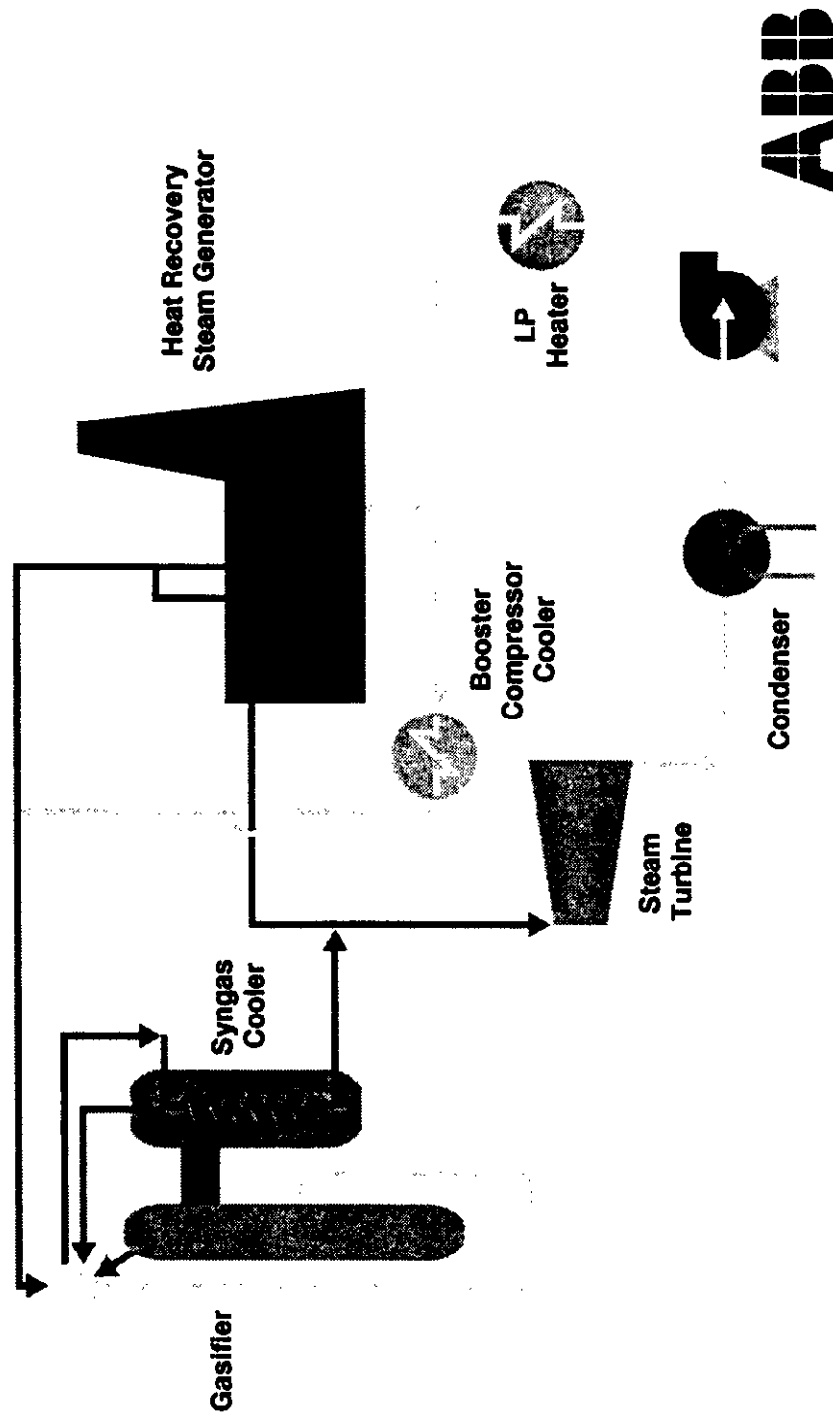


Figure 4

gasifier must be increased to provide the additional energy needed to satisfy the gasifier heat balance. The gasifier stoichiometry would be leaner which would reduce the product gas heating value slightly as gasifier air feed temperature is reduced. The effect on net heat rate favors higher gasifier air temperatures although the effect is not strong. Preliminary studies indicate that reducing the gasifier air temperature from 800 to 500°F degrades the net plant heat rate by 0.7 percent.

Cycle Optimization

For a given stack temperature, the selected feedwater temperature impacts the size of the HRSG economizer bank and the net plant heat rate. As feedwater temperature is raised closer to the stack temperature, the log mean temperature difference for the economizer is lowered and the heat transfer surface area requirement is increased. However, a higher feedwater temperature entering the economizer increases the amount of steam generated by the HRSG. This additional steam generation is partially offset by the additional steam extraction required by the low pressure feedwater heater.

A comparison of feedwater temperatures was performed for the 250°F stack temperature case. The feedwater temperatures that were compared were 200°F and 230°F. The 200°F feedwater temperature, as compared to 230°F, would reduce the amount of main steam generated by about 7,000 pounds per hour. This reduction in steam flow to the turbine causes a corresponding drop in turbine output. The low pressure feedwater heater would require 10,000 pounds per hour less steam extracted from the steam turbine which increases turbine output for the stages after the extraction port. The net effect to the steam turbine is a reduction in steam turbine output of 0.5 MW for the 200°F case as compared to the 230°F case. The result would be a degradation in net plant net rate of 0.9 percent. The design point for the HRSG feedwater temperature was selected to be 230°F.

One of the primary design requirements for this plant is to provide 60 MW net output at 95°F ambient temperature. With the 95°F ambient condition and the gas turbine operating at base load firing conditions, the net plant output is calculated to be approximately 55.6 MW. To obtain an output of 60 MW, various options were investigated.

Peak firing of the gas turbine could provide an additional 8 percent gross output which would satisfy the 60 MW requirement. This would raise the turbine inlet temperatures and improve the net plant heat rate about 1.3 percent as compared to base load firing. However, operation and maintenance requirements would increase and inspection intervals would become more frequent.

Another option to increase plant output is to fire additional fuel in the HRSG (supplemental HRSG firing) to increase the output of the steam turbine. This fuel could be either LBG or natural gas. Thermal efficiency with LBG is 21 percent while thermal efficiency with natural gas is 29 percent. The reason for increased thermal efficiency with supplemental natural gas firing relates to the throttling process which occurs with supplemental LBG firing. When firing LBG in the HRSG, the fraction of LBG which is fired in the HRSG is throttled from high pressure into the HRSG and combusted. The air and coal which was fed into the gasifier to

produce this LBG required power to compress. Normally (without supplemental LBG firing) the LBG fuel stream is fed to the gas turbine and combusted. The high temperature and pressure combustion product stream is expanded to less than atmospheric pressure in the gas turbine. CWL&P chose to specify natural gas supplemental firing in the HRSG as the preferred method to obtain 60 MW net output when the ambient rises to 95°F.

Coal/Char Transport Media

Feeding of coal and char into the gasifier is done with lockhopper systems. The gas used for lockhopper pressurization and fluidization must be inert (very low oxygen content) and must be at a pressure high enough to feed the material into the gasifier which is operating at roughly 300 psia. The transport gas should also be low in oxygen content since any oxygen introduced into the reductor zone of the gasifier would consume some of the low btu gas. The fluids which were considered were steam, inerted flue gas from the HRSG or an adjacent boiler or nitrogen.

Utilization of steam would be convenient but would require the coal to be heated to about 500°F to avoid condensing the steam onto the coal particles. However, char is collected at roughly 1000°F and can utilize steam for pressurization and transport. Steam for the char system will be supplied from a turbine extraction or from the gasifier drum steam.

Flue gas from the HRSG could be used if it were inerted by burning off the excess oxygen. The HRSG flue gas is expected to range in oxygen content between 12 and 16 percent by volume depending on turbine load. The coal would still require heating since the flue gas contains significant quantities of water vapor.

Nitrogen can be purchased for this purpose and there are other plant requirements for nitrogen which will exist regardless of the fluid chosen for transport and pressurization. The use of nitrogen does not require that the coal be heated which reduces capital costs. The compression of nitrogen is assumed to be provided by boiling off the required flow rate utilizing a waste heat source to provide this duty. A nitrogen separation plant would be built and operated by the nitrogen vendor on project supplied foundations assuming a minimum nitrogen use and a five year contract. A reliability study showed that transport of coal with nitrogen has been proven and operated reliably at other gasification facilities. Similar precedent for steam is very limited and not encouraging.

The effects of these options on net plant heat rate were investigated in a preliminary study to see if any significant efficiency advantages were apparent between the options. The differences were very small and the selection was done on capital and operating cost differentials. Nitrogen was selected for the coal system and steam was selected for the char system.

Heat Recovery Steam Generator

The HRSG recovers the major fraction of the total heat added to the steam cycle of the plant. The performance design of the HRSG component of this plant was an iterative process. This process involved the consideration of various heat recovery options which were investigated for the gasifier island.

The HRSG is first surfaced as a standard natural gas fired combined cycle HRSG without any supplemental firing. The surface calculations are specified with a 20°F evaporator outlet pinch point temperature difference and a 10°F approach for the economizer. The low pressure feedwater heater is bypassed for this case. The booster compressor air cooler is not operating. The low temperature economizer section is also bypassed.

The maximum amount of supplemental natural gas firing for the HRSG determines the size and location of the auxiliary burners, while the base load case determines the total economizer section surface requirement. The surface required for the low temperature section is calculated by subtracting the high temperature surface requirements determined during natural gas firing from the total economizer surface requirements. This also defines the maximum steam and water pressures during normal operation.

Hot Gas Desulfurization System

General Electric Environment Services, Inc. (GEESI) has been working on the development of a moving bed hot gas desulfurization process since late 1987 with support from DOE. During initial design discussions, it was determined that a fixed bed process configuration would be difficult to control in a reactor sized for a power plant. Two main concerns were the effects of fines and control of the thermochemical reaction. It was felt that it would be more cost effective to dedicate vessels for absorbing and regenerating.

In selecting a sorbent for the process, GEESI looked for a sorbent that had mechanical durability, good regenerability and chemical reactions which took place at the same conditions as the gas leaving the gasifier. A sorbent with chemical reactions occurring near the conditions of the gasifier would allow the overall process to be more thermally efficient. The first sorbent that was used was zinc ferrite. Although this sorbent worked, there was a problem of material degradation. For this reason, the sorbent was changed to zinc titanate. Zinc titanate has less reduction in sulfur capture ability after repeated cycles of sulfidation and regeneration. The zinc titanate has virtually no zinc loss in the highly reducing coal gas and a higher attrition resistance. It is GEESI's opinion that this sorbent is more compatible with entrained flow gasifiers in both oxygen and air blown operation.

From testing in the pilot unit, it was determined that there is a need to remove chlorides from the gas to prevent fouling of the downstream heat exchangers by Zinc Chloride and to minimize loss of catalyst. GEESI is proposing a sodium bicarbonate injection system to accomplish this. This system would inject sodium bicarbonate into the gas stream prior to the gas entering the absorber.

5.0 OPERATIONS AND MAINTENANCE

The operations and maintenance budget was developed with input from the personnel of Duke Engineering & Services, Duke/Fluor Daniel Operations, ABB CE, ABB-CSSI and CWL&P Operations. Plant layout, equipment specifications, vendor quotations, process descriptions, P&ID's, PFD's and the Project Design Questionnaire were reviewed and the basis for the budget was established. The major assumptions are as follows:

- Costs are for a 60-month operating period commencing with start up of commercial operation and including certain costs that would be incurred during the commissioning period.
- Operations personnel would begin their involvement up to 20 months preceding the commercial operations date. Union labor rates and fringe benefits reflect those currently in effect at CWL&P, with escalation applied to the years of incurred cost.
- Unit costs for fuel and utilities are as stated in the Project Design Questionnaire.
- Plant capacity factors utilized during each year of operation coincide with the BACT document: Year 1 - 30% (2,630 hrs/yr), Year 2 - 50% (4,383 hrs/yr), Year 3,4,5 - 80% (7,013 hrs/yr)
- Natural gas was utilized for turbine peaking operation, limited at 1000 hours per year per the BACT assessment.
- Ash (slag) disposal would be in the existing CWL&P ash pond. Estimates for offsite disposal have been identified.
- Electrical auxiliary power usage, while quantities have been established, have not been included in the O&M cost estimate.
- Existing CWL&P wastewater treatment facilities will be utilized.

Plant Staffing

Mobilization of operations personnel was planned to begin 20 months prior to commercial operations and full staffing reached 4 months before commercial operation.

For estimating purposes, the project staffing level (67 people) is considered a "stand alone" facility. Costs for plant support services (human resource functions, accounting, procurement, etc.) have been included.

6.0 COST ESTIMATE

In arriving at the detailed cost estimate for this project the combined technical and commercial expertise from both Duke Engineering and Services and ABB CE were utilized.

Detailed engineering selections and drawings were produced for all major components, systems and sub-systems to facilitate optimum price development both internally and externally.

Firm price quotations were requested from a minimum of three vendors for each major piece of equipment which make up the entire plant scope. These quotations were reviewed in detail by ABB CE and DE&S for technical and commercial completeness.

Takeoffs from contract quality drawings were made to quantify interstage piping, instrumentation, valving, power and control wiring, conduit, platforms, walkways, building siding, support structures, concrete work, insulation and lagging.

Heavy structural steel fabricators were involved in the pricing of the major components of the gasification plant (e.g. gasifier, heat exchanger pressure vessels, steam drum, coal and char receiving bins/lockhoppers, steam turbine, heat recovery steam generator, etc.) to ensure current labor and material costs, and that optimum designs were reflected in the pricing.

Vendor and in-house cost databases were examined with respect to determining pricing relevance to similar designs/materials selection criteria.

Construction Labor costs to dismantle existing equipment and erect the new systems/components were based on single shift straight time, 40 hour week and local union labor composite costs. The optimum nature of the total construction price reflects the merging of the quality of the ABB CE discrete design and drawing data to the construction and O&M estimating expertise of Duke Engineering and Services. Facilitating the completeness and accuracy of the total construction price was the rather comprehensive analysis of the local site labor conditions.

7.0 Conclusions

The preliminary design of the ABB CE IGCC Repowering Project has been completed and a cost estimate generated. The preliminary design demonstrates that the air-blown, pressurized, entrained flow gasification process is viable for power generation applications. The cost estimate is for an entire stand alone plant with the added complexity of renovating the existing building and maintaining the existing coal fired boilers on-line. The costs were higher than originally expected but the scope of work and the complexity of construction also exceeded the original expectations.

The major plant performance requirements which impacted design were:

- Plant output of 60 MW net at 95°F ambient temperature
- 1265 psia, 950°F steam conditions
- Gas turbine loads from 30 to 100 percent
- Ambient temperature range from 0 to 95°F
- Gasifier performance in both normal and high performance mode
- Steam cycle performance with gasifier not operating and gas turbine firing natural gas

There are several reasons for these results and the cost figures should not be construed as the final cost of an air-blown, entrained flow coal gasification system. The reasons include such factors as system capacity, site limitations, complexity of the preliminary design and first of a kind systems. The capacity, 60 MW net, is small for a utility power plant and contribute to the high cost since many fixed costs that are associated with engineering a plant would be the same for a much larger size plant. Therefore, a larger plant would yield a lower cost per kilowatt. Similarly, the fact that this project is being designed as a first of a kind plant with many systems being designed from scratch adds cost. The site requirements affected the design of the plant which in turn affected the cost. The site requirements and extended scope also added costs which are not normally considered in a commercial plant. Especially with respect to those added costs for:

- Supplying and erecting the natural gas supply line into the site;
- Re-constructing the abandoned rail line(s) into the site;
- Utilizing the existing boiler building
- Inability to use existing steam turbine
- Incorporating a steam turbine bypass
- Electrical transmission equipment/switchgear beyond the primary terminals of the transformer.
- Dismantling and re-arrangement costs associated with integrating the new systems/components with the existing systems/components.

Commercializing this technology will require that a demonstration facility be constructed. A new site needs to be found where significant portions of the plant can be reused without

incurring expensive reconstruction and renovation. The customer should be planning to use the unit as a baseload unit and not as a peaking unit for part time operation. The hot gas desulfurization system and the hot particulate filter system are critical to the success of this technology and need to be developed independent of this project. Fuel and char feed systems which are more cost and space efficient need continued investigation.

PIÑON PINE IGCC PROJECT STATUS

AUGUST 1993

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ABSTRACT

Sierra Pacific Power Company (SPPCo) intends to build the Piñon Pine Power Project, an integrated coal gasification combined cycle (IGCC) plant at its Tracy Power Station near Reno, Nevada. The plant will burn approximately 800 tons of coal per day to generate electricity in a base load application. The Piñon Project was selected by the U.S. Department of Energy (DOE) for funding under Round IV of the Clean Coal Technology Program. The project will demonstrate the use of the KRW

agglomerating fluidized bed gasifier operating in the air blown mode. Hot gas cleanup consisting of particulate and sulfur removal will also be demonstrated.

The Cooperative Agreement between SPPCo and the DOE was executed in August 1992. Foster Wheeler USA Corporation (FWUSA) will provide engineering and construction management services. The M. W. Kellogg Company (MWK) will provide engineering of the gasifier and hot gas cleanup systems.

A discussion of project progress since the 1992 Clean Coal Technology Conference, design and economic considerations, and current project status is presented.

NOTICE

This report was prepared by Sierra Pacific Power Company and its subcontractors Foster Wheeler USA Corporation and The M. W. Kellogg Company pursuant to a Cooperative Agreement partially funded by the U. S. Department of Energy, and neither the Sierra Pacific Power Company nor any of its subcontractors nor the U. S. Department of Energy, nor any person acting on behalf of either:

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INTRODUCTION

In response to DOE issuing its Program Opportunity Notice for Round IV of the Clean Coal Technology program, SPPCo submitted a proposal requesting co-funding of the Piñon Pine Power Project. This proposal was selected for co-funding by the DOE and a Cooperative Agreement between the DOE and SPPCo was executed in August 1992. SPPCo's proposal was for the design, engineering, construction, and operation of a nominal 800 ton-per-day (80 MW net), air-blown integrated gasification combined cycle (IGCC) project to be constructed at SPPCo's existing Tracy Station, a 244 MW, gas/oil-fired power generation facility located on a rural 724-acre plot about 20 miles east of Reno (see Figure 1). SPPCo will own and operate the demonstration plant, which will provide power to the electric grid to meet its customer needs.

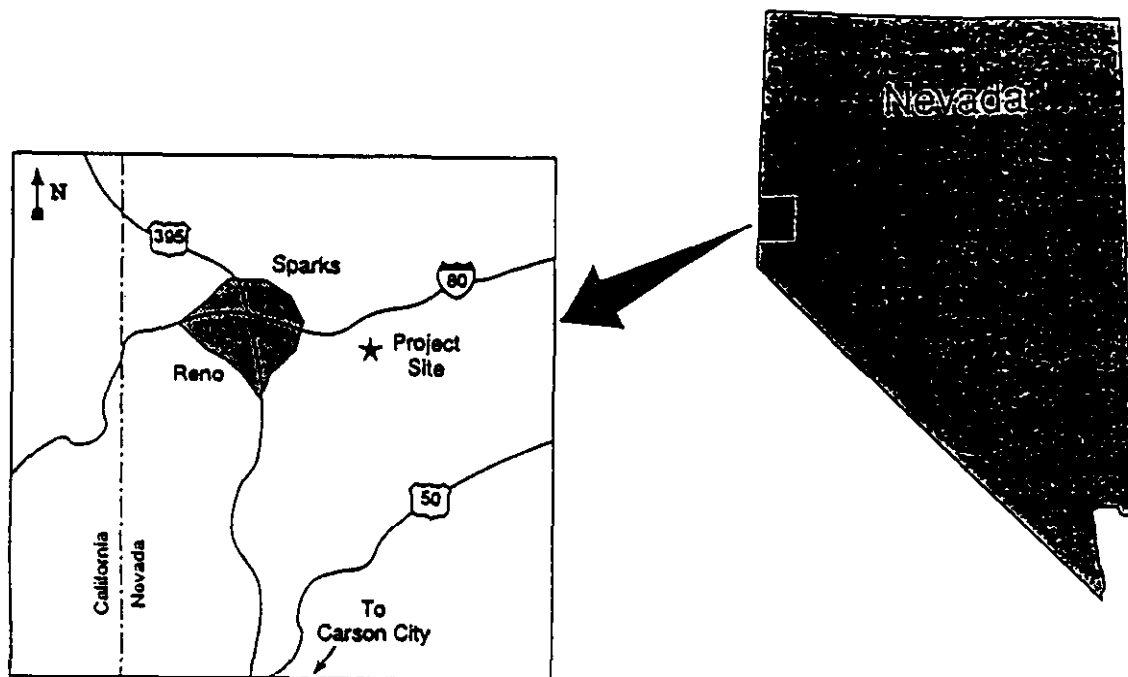


Figure 1. Location of Piñon Pine Power Project.

The KRW agglomerating fluidized bed gasifier will be the basis for the Piñon project. This gasifier, operating in the air blown mode, will provide a low heating value fuel gas to be used to fire a combustion turbine. High temperature exhaust from the combustion turbine will then supply the energy required to generate steam in a heat recovery steam generator (HRSG) for use in a steam turbine. Both the combustion

turbine and the steam turbine will drive generators to supply electricity to the electric power grid.

The KRW gasifier uses an in bed sulfur sorbent. This sorbent also moderates the process temperature in the gasifier and suppresses ammonia formation in the fuel gas.

The project is based on using limestone for in-bed desulfurization. Hot fuel gas cleanup will consist of particulate and sulfur removal. Ceramic candle or similar barrier filters will be used for particulate removal. A regenerable mixed metal oxide sorbent in a fixed bed reactor will be used for removal of remaining sulfur in the fuel gas. The sulfur removal sorbent originally planned to be used was zinc ferrite.

The current project has changed during the past year reflecting changes one would expect from evolving technology. A new combustion turbine utilizing 2350°F firing temperature has been selected. This combustion turbine, the General Electric MS6001FA, improves the plant efficiency and the plant capacity. Cycle design, originally based on zinc ferrite sorbent has evolved and is currently based on the use of other zinc based mixed metal oxide sorbents. These sorbents do not require steam for process temperature suppression as zinc ferrite requires, and have shown better regeneration characteristics than zinc ferrite. Further changes might be expected in the design of the hot gas cleanup system.

The project is currently scheduled to begin start-up in 1996 with operation on coal by the end of the year. To accomplish this, SPPCo has contracted with Foster Wheeler USA Corporation (FWUSA) for the engineering, procurement and construction management of the project. FWUSA in turn has subcontracted with The M. W. Kellogg Company for engineering and other services related to the gasifier island. Figure 2 depicts the project organization.

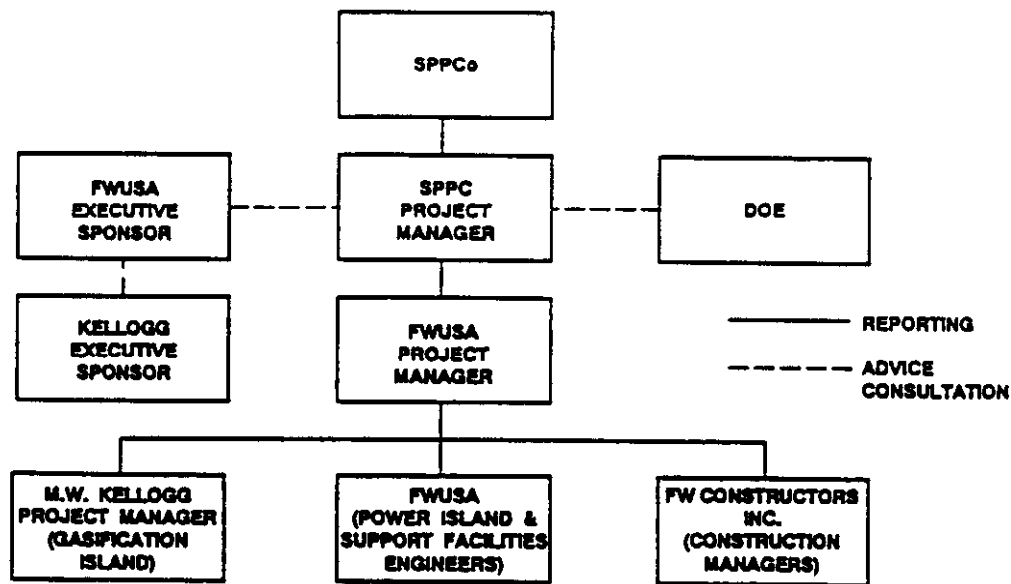


Figure 2. Project Organization Chart.

PROJECT GOALS

SPPCo's goals for the Piñon project are several:

- Piñon must be a least cost generation option.
- Piñon must allow fuel diversification.
- Piñon must conserve water resources.
- Piñon must not be a detriment to the environment.

SPPCo has not added generating capacity or transmission capacity since 1985. System sales have been increasing at an annual rate of 5% over the last ten years. Future load growth is expected to continue at a 4% annual growth rate. The result is the need to add base load generation, peaking generation, and transmission capacity in the near future. The Piñon project will provide a portion of SPPCo's base load generation needs.

SPPCo conducts its own resource planning to meet its customer's needs for electricity. In addition, the State of Nevada requires that utilities prepare and submit their "Resource Plan" to the Public Service Commission of Nevada (PSCN) for review and concurrence. A least cost plan for meeting customer needs is proposed. This plan is based on load growth projections, supply-side and demand-side options, and consideration of other factors such as fuel mix, environmental effects, and financial constraints. SPPCo's resource plan is undergoing PSCN review at this time. The Piñon project is included as a least cost generation option with the added benefits of fuel flexibility and environmental acceptance.

The Piñon project is designed to produce low Btu gas from coal. The coal used for the design basis is a Utah bituminous coal available from a number of suppliers. For start up and as an alternate fuel, either natural gas or propane may be used. The three fuel capability significantly reduces reliability concerns coming from the developmental aspects of the coal gasification and hot gas cleanup processes.'

The arid climate of Nevada and its recent six year drought require that new generation sources be designed to minimize water consumption. A combined cycle plant will use less water than a conventional steam plant simply because its heat rejection requirements are less. An economic and technical evaluation of plant cooling options will decide the method of cooling employed. Reclaiming water from waste streams such as boiler and cooling tower blow-down streams will be considered in the project design.

SPPCo and its management have stressed their commitment toward protecting the environment. Emissions from Piñon will be among the lowest of any coal-fired plant and significantly less than any pulverized coal-fired plant. As a base load unit, any generation it displaces will result in a net improvement in system wide emissions.

PROJECT DESCRIPTION

Technical Overview of Process

Raw coal will be received at the plant in weekly unit trains consisting of 100-ton automated bottom dumping railcars. Once unloaded, coal will be stored and transported within enclosures to minimize dust emissions. The coal is received and stored as 2" x 0 and is then transferred to a preparation area where it is crushed, dried, sized and passed to a day-bin for feeding the gasifier island. Sized limestone and dried coke breeze (for startup) are received by covered truck and are also stored in silos close to the gasifier island.

The two major components of the plant are the gasification island and the power island. Figure 3 is a block diagram of the processes to be employed in the Piñon project.

In the gasification island, crushed and sized coal and limestone are metered through lockhoppers and fed pneumatically through a central feed tube in the bottom of the gasifier. The temperature of the bed is controlled by metering the air and steam into the gasifier's central jet. The coal/limestone bed is maintained in a fluidized state in the gasifier via gas recirculation. Partial combustion of char (devolatilized coal) and gas occurs within the bed to provide the heat necessary for the endothermic reactions of devolatilization, gasification, calcination, and desulfurization. Ash and spent limestone are removed from the bottom of the bed. A diagram of the KRW gasifier is shown in Figure 4.

Coal gas leaving the gasifier passes through a cyclone to remove the majority of the particulate matter that is returned to the fluidized bed. The gas leaving the gasifier is cooled to 900-1100°F before entering the hot gas cleanup section. Ceramic candle filters or similar barrier filters remove essentially all the remaining particulate material prior to the clean gas entering the sulfur sorbent bed. In the desulfurizing reactors, nearly all the remaining sulfur compounds are removed in a fixed bed of zinc based mixed metal oxide sorbent. The sorbent is subsequently regenerated with nitrogen diluted dry air. This process sends the regeneration gas stream to the

sulfator where the sulfur oxides react with additional or fresh lime and air to form calcium sulfate, which exits the system along with the coal ash in a form suitable for landfill, or potentially to be used as a commercial byproduct.

The clean coal gas will be delivered to a General Electric MS6001FA combustion turbine/generator which will produce approximately 61MW on this fuel. This combustion turbine is also designed to fire either natural gas or propane and blends of these fuels with coal gas.

The MS6001FA is a new machine offering a high firing temperature (2350°F) and a high exhaust temperature (1100-1125°F) making it very efficient in combined cycle operation. Exhaust gas from the combustion turbine is used to generate steam in a heat recovery steam generator (HRSG). Steam generated in the HRSG and the gasifier process are combined and superheated in the HRSG. Current heat balances are based on a 900°F /900psig steam cycle. With this steam cycle, a steam turbine/generator producing approximately 40MW will be used. With the 1100°F combustion turbine exhaust, evaluation of higher temperature and pressure steam cycles will be performed. A further improvement in capacity and efficiency is expected.

As efficiency has improved, water consumption per unit generation is reduced. This is due to reduced evaporation losses from lower heat rejection requirements. In addition, blow-down streams will be evaluated for water treatment and re-use, further reducing plant water consumption.

Plant Performance

Based on using the 900°F/900psig steam cycle, the Piñon project will be 15-20% more efficient than SPPCo's current coal-fired units. The expected performance is summarized in Tables 1 and 2 below. This represents a significant improvement in SPPCo's system heat rate. Using coal fuel and its demonstrated price stability relative to other fuels, Piñon will deliver least cost generation to SPPCo's customers.

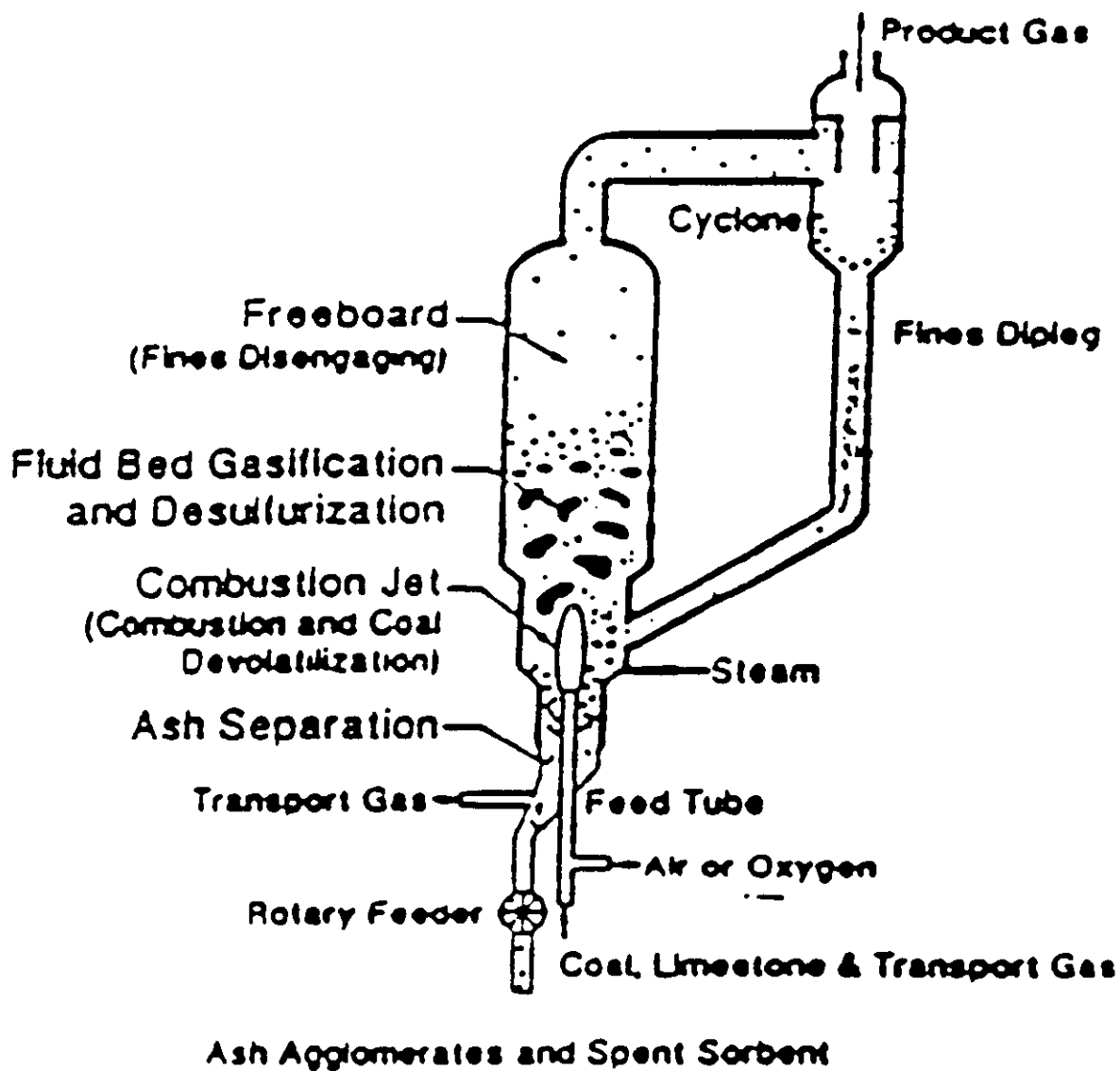


Figure 4. KRW Gasifier.

Expected Plant Performance*	
Heat Input (10 ⁶ BTU/Hr)	805
Combustion Turbine Power (MW)	61
Steam Turbine Power (MW)	40
Steam Turbine Conditions (psia/°F)	900/900
Station Load (MW)	6
Net Power Output (MW)	95
Heat Rate (BTU/kWh)	8470

*At 50°F and 4280' elevation, evaporative cooler off.

Table 1. Expected Plant Performance

Expected Performance vs. Temperature			
Ambient Temperature	25°F	50°F	95°F
Expected Performance - Coal			
Net Power Output MW	95	95	90
Heat Rate Btu/kWh (HHV)	8470	8470	8554
Expected Performance - Natural Gas			
Net Power Output MW	91	88	84
Heat Rate Btu/kWh (HHV)	8103	8144	8207

Table 2. Expected Performance vs. Temperature

Plant Layout

Integration of the Piñon project into the existing Tracy plant is shown conceptually in Figure 5. Piñon will be located west of Tracy Unit 3. Control of the Piñon facility will be through the control room of Unit 3 which will be modified to include Piñon's distributed control system. The Unit 3 crane rails will be extended to service the combustion and steam turbines of the Piñon plant. The existing rail spur used for oil delivery will be extended and will be used for coal delivery and unloading. The Piñon switchyard will be integrated into the existing Tracy plant switchyard.

PROJECT STATUS, SCHEDULE, AND BUDGET

The schedule for the Piñon project is shown in Figure 6. Project activities to date have primarily been in permitting and preliminary design. Prior to the start of construction several key regulatory and permitting items must be completed.

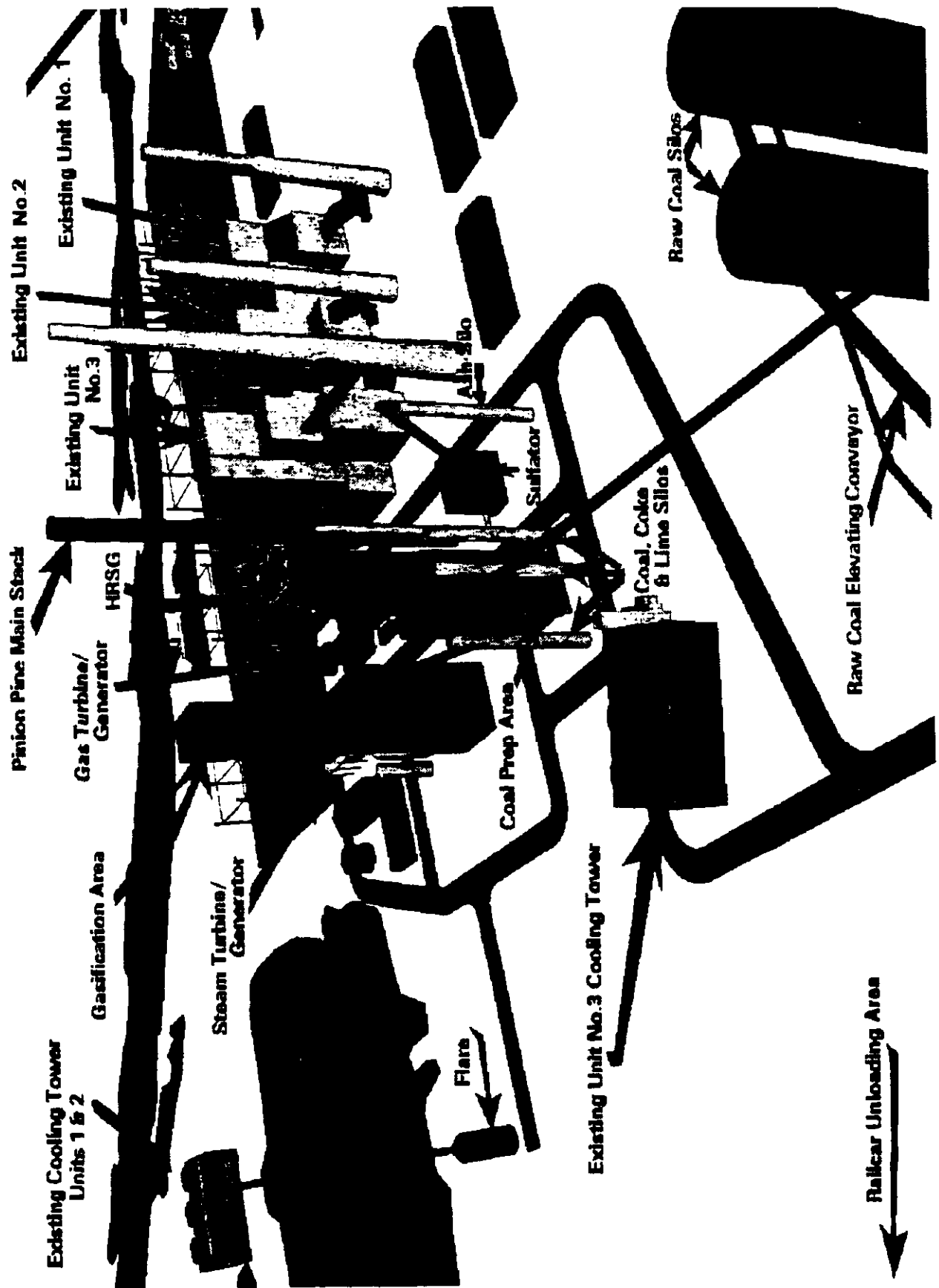


Figure 5. Plant Layout

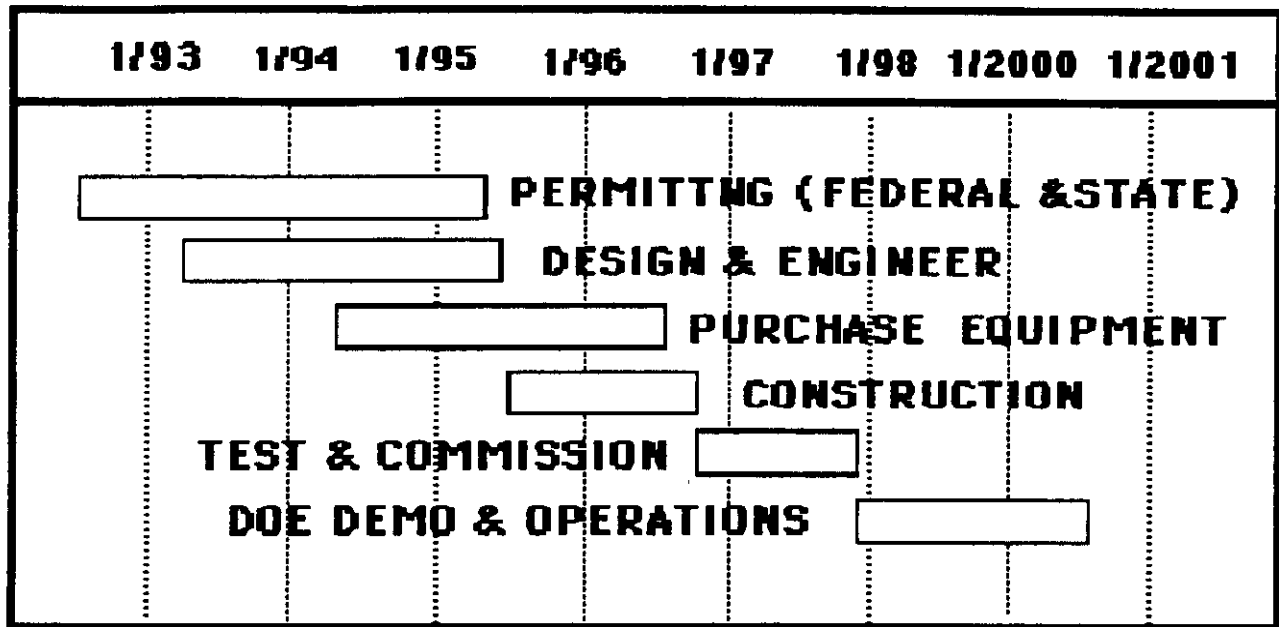


Figure 6. Schedule for Piñon project.

Resource Plan

The 1992 Electric Resource Plan was submitted to the PSCN July 1, 1992. Hearings on this plan were held. The decision from the hearings requested that SPPCo continue with the project, subject to review in a Revised Resource Plan to be filed April 1, 1993. Preliminary design of the Piñon project has been continuing. Continued design efforts have resulted in improvements in capacity, efficiency, and cost. The improvements are shown in Table 3.

	1992 Filing	1993 Re-Filing
Net Power (MW)	77	95
Heat Rate (Btu/kWH, HHV)	8900	8470
Cost per kW (1992 \$) (SPPCo portion after cost sharing)	1090	978

Table 3. Comparison of Resource Plan Filings

Hearings on the revised resource plan are in progress with a decision expected in September 1993. With the improved performance and cost, Piñon remains a least cost option for base load coal-fired power supply.

NEPA/EIS

Federal funding of the Piñon project automatically invokes environmental review under the National Environmental Policy Act (NEPA). A determination has been made that an Environmental Impact Statement (EIS) is the appropriate level of documentation for the NEPA review. The DOE is the lead agency for the NEPA reviews. Under contract to SPPCo., EBASCO Environmental has been assisting the environmental engineering and analysis during the NEPA review by the DOE. The scheduled date for the Record of Decision is March 31, 1994. Funding for Phase II of the project, Procurement, Construction and Start-up is, contingent on receiving a favorable Record of Decision.

UEPA Process

The Utility Environmental Protection Act (UEPA) requires that SPPCo apply for a permit for construction. This application must address the following areas:

- Need for the project.
- An analysis of project alternatives.
- An assessment of environmental impacts.
- Proposed mitigation measures to reduce or eliminate environmental disturbance.
- Description of the project and its facilities.

The UEPA application is filed with the Public Service Commission of Nevada. On completion of a public review period and after all necessary construction, operating, and special use permits have been obtained, the PSCN will issue a Permit to Construct the Piñon Pine project.

Design

Project design has been ongoing since the execution of the Cooperative Agreement, August 1, 1992. Preliminary design work has been in support of permitting activities and selection of key equipment process items. Specifically, selection of the combustion turbine and the sulfur sorbent for the hot gas cleanup section have allowed preliminary process design to accelerate. The combustion turbine selection dictates the plant capacity and balance of plant design. Selection of the sorbent, primarily due to process steam requirements of particular sorbents, was required in order to proceed with the design of the steam cycle.

Construction and Start-Up

Construction is scheduled to be completed in the Fall of 1996. Plant start-up will be on natural gas fuel. Following mechanical completion of the gasifier, operation on low Btu gas from coal is expected by December 1996.

Demonstration

Project demonstration will continue through July 2000. During this period, the KRW gasifier operating in the air blown mode will be demonstrated. Also, hot gas cleanup employing particulate filtration and sulfur removal will be demonstrated. Operation of the plant will be demonstrated on low sulfur western coal. Operating data on higher sulfur eastern coal will also be obtained during the demonstration phase.

Project Budget

The project is expected to cost approximately \$270 million through its completion with approximately half of the funds coming from the DOE. In addition to capital costs; operating expenses, maintenance expenses, and fuel costs will also be shared by SPPCo and the DOE during the start-up and demonstration phases of the plant operation.

THE WABASH RIVER COAL GASIFICATION REPOWERING PROJECT PROGRAM UPDATE

**Phil Amick
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Destec Engineering, Inc.
Houston, Texas**

**Jim Cook
Project Director
PSI Energy, Inc.
Plainfield, Indiana**

ABSTRACT

PSI Energy, Inc. and Destec Energy, Inc., are participating in the Department of Energy (DOE) Clean Coal Technology Program to demonstrate coal gasification repowering of an existing generating unit affected by the Clean Air Act Amendments ("CAAA"). A Clean Coal Round IV selection, the project will demonstrate integration of the existing station steam turbine generator and auxiliaries, the new combustion turbine generator, heat recovery steam generator tandem and the coal gasification facilities to achieve improved efficiency and reduced installation costs.

The Wabash Project achieved several significant milestones in the second quarter of 1993, including certification by the Indiana Utility Regulatory Commission, and receipt of the air permit from the Indiana Department of Environmental Management. The Department of Energy completed the Environmental Assessment in this period as well, and issued a Finding-of-No-Significant-Impact for the Wabash Project.

Construction of project facilities began in the third quarter of 1993. Upon completion in 1995, the project will not only represent the largest coal gasification combined cycle (CGCC) power plant in operation in the United States but will also emit lower emissions than other high sulfur

coal fired power plants and improve the heat rate of the repowered unit by approximately twenty percent.

INTRODUCTION

The Wabash River Coal Gasification Repowering Project (Wabash Project) is a joint venture of Destec Energy, Inc., (Destec) of Houston, Texas and PSI Energy, Inc. (PSI) of Plainfield, Indiana, who will jointly develop the coal gasification combined cycle (CGCC) power plant. PSI will be responsible for the new power generation facilities and the modification of the existing unit, and Destec will be responsible for the coal gasification plant.

Destec's coal gasification technology will be used to repower one of the six units at PSI's Wabash River Generating Station in West Terre Haute, Indiana. The CGCC power plant will produce a nominal 262 net MW of clean, energy efficient capacity for PSI's customers. In the repowered configuration, PSI and its customers may additionally benefit because of the role the Wabash Project plays in PSI's compliance under the CAAA regulations. The CGCC plant will dispatch for base load in PSI's system on the basis of both efficiency and environmental emissions. The project will use locally mined, high sulfur coal.

BACKGROUND

The Destec Coal Gasification process was originally developed by the Dow Chemical Company during the 1970's in order to diversify its fuel base from natural gas to lignite and other coal. The technology being used at Wabash is an extension of the experience gained from that time through pilot plants and up to the Louisiana Gasification Technology, Inc. (LGTT) facility in Plaquemine, Louisiana, a 160 MW coal gasification facility which has been operating since April 1987.

Sargent & Lundy will provide engineering services to PSI for the design and procurement of the modifications to the existing station and the new power block equipment, and will provide the system integration interface to Destec. PSI will manage the construction of, own and operate

the power generation facilities. Destec will manage the construction of, own and operate the coal gasification and air separation facilities. Dow Engineering Company, previously engineer for the LGTI facility, will provide engineering services to Destec for the gasification plant. Liquid Air Engineering Corporation has received a turnkey contract for the air separation plant.

The major provisions of the agreements establishing the PSI and Destec relationship are:

PSI

- to own and operate the power generation facility
- to build the power generation facility to an agreed common schedule
- to furnish Destec with a site, coal, power and services
- to provide stormwater and wastewater facilities .

DESTEC

- to own and operate the coal gasification facility
- to build the gasification facility to an agreed, common schedule
- to guarantee performance of the coal gasification facility
- to meet environmental conditions
- to deliver syngas and steam to the power generation facility

The structure of the Gasification Services Agreement which defines these provisions allows the Power Generation Facility and the Coal Gasification Facility to be integrated for high efficiency.

FACILITIES INTEGRATION

The site of the project is PSI Energy's Wabash River Generating Station, located near Terre Haute, Indiana. Only Unit 1 of the six existing units will be repowered as part of the project. The existing pulverized coal fired boiler will be decommissioned and the steam turbine, a Westinghouse reheat unit originally placed in service in 1953, will be driven by steam from the new facilities. Other existing facilities to be used by the project include the railroad, coal unloading facilities, and the ash pond, in addition to the existing steam turbine generator

auxiliaries, condenser and substation. No new construction will be required within the existing boiler and turbine buildings except for the steam piping interconnection.

New construction will take place in two areas (Figure 1). A 15 acre plot containing the gasification island, oxygen plant, water treatment and gas turbine-heat recovery steam generator block is on a hill overlooking the existing station. The new wastewater and storm water ponds will be located nearby in an area previously used as an ash pond. Coal for the Wabash Project, a high sulfur midwestern bituminous, will be stored separately from the compliance coal that will be burned in Units 2 through 6 of the existing station. Existing coal unloading facilities will be shared, with the remainder of the coal handling equipment being part of the new installation.

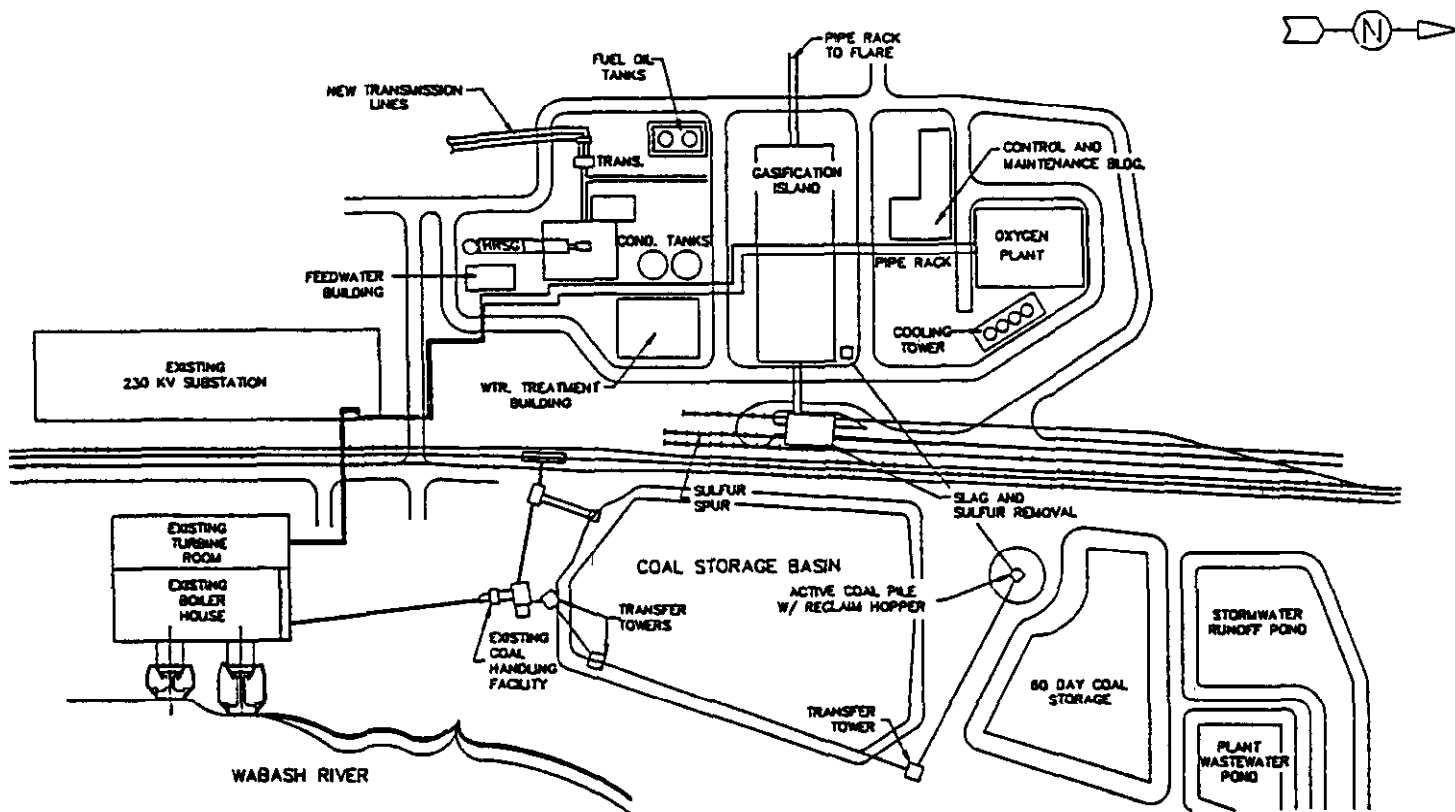


Figure 1 - Site Plan

New facilities for the project are listed below. Destec and PSI will independently design, procure equipment and construct their respective portions of the Wabash Project. However, cooperation in design efforts and integration of systems has allowed the participants to reduce costs by minimizing redundant systems and maximizing efficiency by thermal integration.

PSI:

- Combustion turbine
- Heat recovery steam generator
- Modifications to coal handling
- Oil storage tanks
- Piping additions
- Water treatment facilities
- Control room and buildings
- Modifications to steam turbine

DESTEC:

- Slurry preparation
- Gasification and heat recovery
- Slag removal
- Gas cleanup
- Sulfur recovery
- Oxygen plant
- Control, administration & maintenance building

Repowering the existing unit, and utilizing the existing site facilities mentioned above, in addition to the existing steam turbine generator, auxiliaries, and electrical interconnections, represent an installed cost savings of approximately \$30 to \$40 million as opposed to an entirely new, greenfield installation.

THERMAL INTEGRATION

The Destec gasification process features an oxygen-blown, two stage entrained flow gasifier. The synthetic fuel gas (syngas) is piped to a General Electric MS 7001F high temperature combustion turbine generator. A heat recovery steam generator (HRSG) recovers gas turbine exhaust heat. In the gasification process, coal is ground with water to form a slurry. It is then pumped into a gasification vessel where oxygen is added to form a hot raw gas through partial

combustion. Most of the non-carbon material in the coal melts and flows out the bottom of the vessel forming slag - a black, glassy, non-leaching, sand-like material. Particulates, sulfur and other impurities are removed from the gas before combustion to make it acceptable fuel for the gas turbine. Sulfur is removed from the syngas using conventional "cold" gas clean-up systems similar to those used in crude oil refineries around the world. Some of these systems must operate at near ambient gas temperatures, necessitating the reduction of the syngas temperature by heat exchange to other streams. Condensate, feedwater and steam streams are exchanged between the gasification island and the power block HRSG to maximize efficiency by making the best use of lower levels of heat available in each area. (See Figure 2).

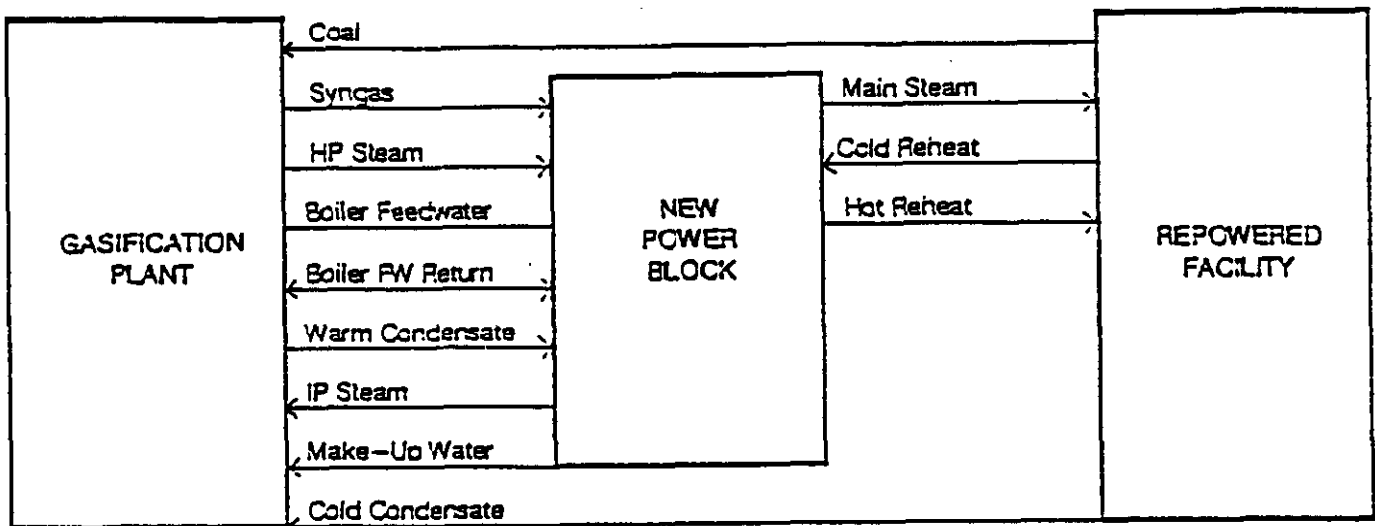


Figure 2 - Simplified Thermal Integration Diagram

The combustion turbine generator will produce approximately 192 MW. Steam generated by the combustion turbine heat recovery steam generator in the gasification island will supply the existing steam turbine generator to produce an additional 105 MW. Plant auxiliaries in the power generation and coal gasification areas and the oxygen plant will consume approximately 35 MW, for a net electrical production of approximately 262 MW.

The new power generation facility will include additional water treatment systems. The combustion turbine has steam injection for NO_x control. The amount of this injection flow is reduced compared to conventional systems because the syngas burned in the combustion turbine

is moisturized at the gasification facility, making use of low level heat in the process. This flow is continuously made up at the power block by clarification and treatment of river water.

The air separation unit (ASU), which provides oxygen and nitrogen for use in the gasification process, is not an integral part of the plant thermal balance. The ASU will utilize services such as cooling water and steam from the gasification facilities, and will be operated from the gasification plant control room.

OPERATIONS

Destec and PSI will independently operate their respective gasification and power generation facilities. Operating interface parameters and other key data will be interchanged continuously between the gasification and power generation control rooms. In normal operation, syngas production will follow combustion turbine fuel demand. Thermal balance between the facilities is flexible to a certain extent, utilizing the heat recovery steam generator and gasification facility heat exchangers, and will follow the syngas production.

Operation of the facilities will be closely coordinated during startup and shutdown. The combustion turbine operates on auxiliary fuel (oil) at low loads during startup and shutdown. A "flying switch" will be made to syngas and the combustion turbine will ramp up to full load at its normal rates.

The CGCC plant will have two commercial byproducts during operation. Elemental sulfur removed via the gas clean-up systems will be marketed to fertilizer plants and other sulfur users. slag, the sand-like material from the gasifier will be available for use as a construction material.

COST AND EFFICIENCY

Integration of the new and existing power generation facilities and the new gasification facilities have resulted in lower installed cost and better efficiency than other "environmentally equivalent" coal based power generating projects. Reduced development effort and shorter schedule can also

result from choosing to repower existing stations, because of the siting problems that even clean coal technologies may have for greenfield installations.

The net plant heat rate for the entire new and repowered unit is forecast to be approximately 9025 Btu/kWh, representing an approximate 20 percent improvement over the existing unit. Certain major component manufacturer margins and guarantees (combustion turbine, HRSG, HTHRU, etc.) are included in this energy balance calculation; actual operation is expected to be slightly better. This heat rate will be among the lowest of commercially operated coal-fired facilities in the United States.

The total estimated installed cost for the Project is \$362 million, of which Destec's and PSI's facilities are \$240 million and \$122 million, respectively. These estimated figures include escalation through 1995, environmental and permitting costs, and startup costs. On this basis, the total estimated installed cost of the project is approximately \$1380 per kW of net generation. The U.S. Department of Energy's Clean Coal Technology Program (Round IV) provides partial funding for the project. PSI and Destec will provide the balance of the funds for their respective portion of the job. The DOE funding reduces the estimated installed cost to approximately \$820 per kW of net generation.

ENVIRONMENTAL BENEFIT

The plant will be designed to substantially outperform the standards established in the CAAA for the year 2000. The Destec technology to be employed will remove at least 98 percent of the sulfur in the coal. SO₂ emissions will be less than 0.20 pounds per million Btu's of fuel. NO_x emissions from both the gasification block and the power block are expected to be less than 0.7 lb/MWh. CO₂ emissions will also be reduced, approximately 21 percent on a per kilowatt-hour basis by virtue of the increased system efficiency. Figure 3 compares emissions of current Wabash Unit 1 with expected emissions from the Project.

PROJECT ENVIRONMENTAL DATA

A. EXPECTED PROJECT EMISSIONS

CGCC EMISSIONS	SO ₂	NO _x	CO	PM	PM-10	VOC
Gasification Block Tons/Yr.	23	18	124	25	20	12
Power Block Tons/Yr.	204	774	374	46	42	13
Total CGCC Tons/Yr. (note 1)	227	792	498	71	62	25

B. COMPARISON TO EXISTING UNIT

EMISSIONS, LBS/MWH	SO ₂	NO _x	CO	PM	PM-10	VOC
Unit 1 Boiler	38.2	9.3	0.64	0.85	0.85	0.03
CGCC	0.21	0.75	0.47	0.07	0.06	0.02
EMISSIONS, LBS/MMBtu						
Unit 1 Boiler	3.1	0.8	0.05	0.07	0.07	0.003
CGCC	0.02	0.08	0.05	0.01	0.01	0.003

Note: 1) Based on 2,111,160 MW/hr estimated annual generation (268 MW at 90% capacity factor)

Figure 3 - Environmental Emissions

By providing an efficient, reliable and environmentally superior alternative to utilities for achieving compliance with the CAAA requirements, the Wabash Project will represent a significant demonstration of Clean Coal Technology.

CURRENT PROGRESS

The Wabash Project was selected by the DOE as part of the Clean Coal Technology Program's Round IV in September 1991. In May 1993, the Department of Energy completed an Environmental Assessment of the Project and issued a Finding-of-No-Significant-Impact. Also, in May 1993, the Indiana Utility Regulatory Commission completed its certification of the project, and the Indiana Department of Environmental Management issued air permits to the project participants. Completion of these major regulatory milestones to support the project

construction goals was a result of strong local support, the cooperative spirit of the involved agencies and the strong benefits of CGCC technology.

Engineering for the Project began late in 1991. Process engineering was completed in the first quarter of 1993. Both Destec and PSI are now more than 60 percent complete on overall engineering for their respective portions of the work. Procurement is nearly complete for the engineered equipment. Major equipment and long lead items, such as the gas turbine generator, main air and oxygen compressors, heat recovery steam generator and all major vessels are in fabrication.

Field construction of the project facilities began in the third quarter of 1993, less than two years after selection and approximately one year after completion of the Cooperative Agreement. Construction duration will be less than two years. This period includes two months of commissioning and one month of testing prior to full load operation.

**TAMPA ELECTRIC COMPANY INTEGRATED GASIFICATION
COMBINED CYCLE SYSTEM**

September 9, 1993

DOE - Clean Coal Program

D. E. Pless

TECO Power Services

702 North Franklin Street

Tampa, FL 33602

INTRODUCTION

Tampa Electric Company (TEC) is starting detailed engineering for its new Polk Power Station Unit #1. This will be the first unit at a new site in Polk County, Florida, just east of Tampa. We will use Integrated Gasification Combined Cycle (IGCC) Technology. The unit will utilize oxygen-blown entrained-flow coal gasification, along with combined cycle technology, to provide nominal 250MW (net) generation.

The project is partially funded by the U.S. Department of Energy (DOE) under Round III of its Clean Coal Technology Program. Use of a new hot gas clean-up system will highlight this demonstration of IGCC technology on a commercial scale.

OBJECTIVE

Obviously, the main objective of any power plant is to provide electric power for the utility's Customers. This unit is an integral part of Tampa Electric Company's generation expansion plan. That plan requires baseload capacity to be in service in the summer of 1996. TEC's objective is to build a coal-based generating unit providing reliable, low cost electric power, using IGCC technology to meet those requirements.

Demonstration of the oxygen-blown entrained-flow IGCC technology is expected to show that such a plant can achieve significant reductions of SO₂ and NO_x emissions when compared to existing and future, conventional coal-fired power plants. In addition, this project is expected to demonstrate the technical feasibility of a commercial scale IGCC unit using hot gas clean-up technology.

COST

The current expected cost for this unit is about 500 million dollars, plus or minus a few million. Being a demonstration project, we are finding every day that we haven't yet fully defined all of the technical requirements for the project. As we develop these aspects, we find that each one has an associated cost impact; some positive, some negative. Even the major suppliers such as General Electric and Texaco are still finalizing designs related to this project. Although the GE

7F is a commercial product, General Electric is still polishing integration concepts for the low BTU/IGCC system. The same holds true for Texaco. Their gasification system is well proven, but as they have worked to integrate it into a cost effective IGCC system, they too are learning more and more about how their own system impacts the other parts of the project.

Back to the 500 million dollars, plus or minus. If you divide that figure by 250MW, it results in about \$2,000/KW. When you apply the DOE funding, this number drops to about \$1600/KW; still not as low as we would like it to be, but for a first of its kind commercial installation, it is not too bad. What utilities look for are cost effective, reliable ways to install new operating power plants. However, many times, capital costs are not the total deciding factor on what technology to use.

In this day and age, coal is increasingly more difficult to permit. Tampa Electric Company's system needs baseload generating capacity. The operating costs for oil and/or natural gas are higher than coal, especially when you look at the recent past and the potential volatility of these fuel prices. In addition, the IGCC concept offers emissions which approach those of the natural gas-fired combustion turbines. That's why we believe, when all factors are considered, IGCC represents Tampa Electric Company's best option for this new capacity requirement.

The primary IGCC competition in the short term U.S. market is natural gas fired combined cycle. For the IGCC to compete, natural gas prices must rise relative to coal prices, and/or IGCC capital costs must decrease. Natural gas prices have in fact increased over the last year. Whether these trends continue, and how they continue is anybody's guess.

Natural gas prices are not in the technology suppliers control but are still very important. Capital cost is in the control of the technology suppliers. Reduction in capital costs of IGCC technology is required to ensure its long term competitiveness. Capital cost reduction probably represents the most significant challenge for IGCC technology suppliers. Through economies of scale or other means, such as reduced design margins, repetitive designs and improved fabrication techniques, IGCC capital cost must be reduced for the IGCC technology to be consistently competitive in the future.

Tampa Electric Company's economic justification for this project has been, in large part, due to the \$120 million funding from the DOE. The Clean Coal Technology Program provides a bridge between the economics of today and those of the future. Tampa Electric is proud to be taking a leadership position applying these funds to further IGCC technology for future use by other utilities in the U.S. and the world.

SCHEDULE

The total project, IGCC Combined Cycle, is expected to be put into service July 1996. Originally, we had considered using the 7F machine in simple cycle to meet Tampa Electric Company's peaking capacity requirements for the summer of 1995 and the fall of 1996. As you are aware, Tampa has an extreme air conditioning load requirement during the summer and, as many of you may not know, TEC has a similar peak in the winter time when the cold north winds bring the temperatures crashing down to the 30°F range. Native Floridians can not tolerate this extremely cold temperature and some begin using their electric heating elements when the temperature drops below 40°F. This causes peaks as high as or higher than the summer peaks, but usually for a much shorter duration. As Tampa Electric Company has continued to look at their generation needs, this peaking requirement during the summer of 1995, and the following winter, has shown a recent shift allowing us to move the installation of the 7F CT to coincide the overall IGCC requirements for total system operation in July of 1996. This will allow us to perform a more efficient and effective site development and overall project installation thereby saving capital dollars.

The current schedule requires permits be received in the early part of 1994, with construction following immediately thereafter, because site will require a massive amount of development work requiring considerable time to convert the existing mine cuts into a usable cooling water canal. The two main pieces of equipment impacting our schedule are the 7F Combustion Turbine scheduled to be delivered in the middle of 1994 and the Radiant Syngas Cooler scheduled to be delivered in May 1995.

PARTICIPANTS

U.S. Department of Energy

The Department of Energy has entered into a Cooperative Agreement, for demonstrating IGCC technology with HGCU, with TEC under Round III of the Clean Coal Technology (CCT) Program. Project Management is based in DOE's Morgantown Energy Technology Center in West Virginia.

Tampa Electric Company

Tampa Electric is responsible overall for the implementation of this project. TEC is the "Participant" and has repayment responsibilities to DOE.

Tampa Electric Company (TEC) is an investor-owned electric utility, headquartered in Tampa, Florida. It is the principal, wholly owned subsidiary of TECO Energy, Inc., an energy related holding company heavily involved in coal mining, transportation, and utilization. TEC has about 3200MW of generating capacity, of which 97% is coal-fired. TEC services approximately 470,000 customers in an area of about 2,000 square miles in west-central Florida, primarily in and around Tampa, Florida.

TEC owns five generating stations; two are coal-fired (2850 MW), two are heavy oil-fired (250MW), and one is natural gas-fired (11MW). TEC also has four combustion turbines with about 160MW of generating capacity, used for start-up and peaking.

TECO Power Services

TECO Power Services (TPS) is also a subsidiary of TECO Energy, Inc., and an affiliate of TEC. This company was formed in the late 1980's to take advantage of the opportunities in the non-utility generation market. TPS has recently started up a 295MW natural gas-fired combined cycle power plant in Hardee County, Florida. Seminole Electric Cooperative and Tampa Electric Company are purchasing the output of this plant under a twenty-year power sales agreement.

Emissions

The primary source of emissions from the IGCC unit is combustion of syngas in the advanced CT (GE 7F). The exhaust gas from the CT will be discharged to the atmosphere via the HRSG stack. Emissions from the HRSG stack are primarily NO_x and SO₂ with lesser quantities of CO, VOC, particulate matter (PM). SO₂ and NO_x emissions are expected to be about 0.2lb/mmBtu and 0.1 lb/mmBtu, respectively, for the 100% CGCU mode. The emission control capabilities of the HGCU system are yet to be fully demonstrated. Therefore, some emission estimates are higher compared to estimated emissions from the CGCU system. After the completion of the 2-year demonstration period, the lower emission rates from the CGCU system must be achieved to meet permit requirements. It is expected that at least 96 percent of the sulfur present in the coal will be removed by the CGCU and HGCU systems.

The advanced CT in the IGCC unit will use nitrogen addition to control NO_x emissions during syngas firing. Nitrogen acts as a diluent to lower peak flame temperatures and reduce NO_x formation without the water consumption and treatment/disposal requirements associated with water or steam injection NO_x control methods. Maximum nitrogen diluent will be injected to minimize NO_x exhaust concentrations consistent with safe and stable operation of the CT. Water injection will be employed to control NO_x emissions whenever backup distillate fuel oil is used.

Demonstration

Part of the Cooperative Agreement for this project is the two-year demonstration phase. During this period, it is planned that about four to six different types of coals will be tested in the operating IGCC power plant. These coals will be classic eastern coals; Eastern being defined as east of the Mississippi. We would expect to test burn such coals as Illinois 6, Kentucky 9, Eklhorn 3, etc. The results of these tests will provide data for utilities in many coal producing areas to be able to determine operating characteristics and economics related to using IGCC in their areas with local coals. The results of these tests will compare this unit's efficiency, operability, and costs, and report on each of these specific test coals against the design basis coal.

These results should provide a menu of operating parameters and costs which can be used by utilities in the future as they make their selection on methods for satisfying their generation needs, in compliance with environmental regulations.

COMMERCIALIZATION

We have found this technology is vastly different from what utilities are accustomed to using. The non-technical or business issues such as project management, and contract administration also have significantly different requirements. The business issues must be successfully addressed by both the utilities and the different technology suppliers, in order for IGCC power plants to achieve ultimate commercial success. In our project, this has been a major task: meshing cultures from the utility, refinery, industrial and sulfuric acid industries. Although it has been very different for us, we have successfully achieved a team concept that will be the template for IGCC Units built in the future.

Major contributions to IGCC efficiency improvements have been made in the combustion turbine/combined cycle portions of the plant. What needs to happen now are continued significant improvements in the gasification and integration side. Not only in operating efficiency but also cost effectiveness and environmental controls.

This has been the case with all fuel burning technologies in the past. The actual combustion of a fuel produces the side effects that many consumers are concerned about. The entire gasification industry needs to continue to develop methods for processing coal into fuelgas in a manner that minimizes emissions of environmentally sensitive constituents. We feel there should be intensified technology vendor effort in the general gasification area to develop and implement these needed improvements, in order to support long term commercial viability of IGCC.

One of the major hurdles we have had in this project, is adapting to the contracting requirements for these new and different technologies. The first item we encountered was the requirement to buy a license. This is a concept totally new for most utilities. In addition to the gasification technology license which we expected, we also found requirements for licenses which are typical in businesses for acid gas removal, sulfur recovery, and sulfuric acid production. The license

provides information necessary to implement this technology, but usually not the equipment necessary to do it. When a utility buys a boiler, the supplier provides the required hardware as well as the technology, in the overall pricing as a total package.

The technology that is licensed is "know-how" and generally not formally written down. It is therefore very difficult to monitor and/or control. Most technology licensors have resisted defining what it is they are concerned about protecting. Therefore it is difficult for us to draft language in a confidentiality agreement to protect something which is not specifically detailed. Most vendors would like to license their technology by describing what is not covered rather than what is. That way their technology definition is more broad.

In addition to technologies, guarantees are also significant differences with which utilities are not accustomed to dealing. The license of a technology generally applies only to the process performance and not necessarily the overall end product. Licensors look towards equipment vendors to provide the equipment guarantees. This leads to split responsibilities and difficult, contracting. If this system doesn't work, then it's up to the utility to determine who is at fault and try to negotiate resolution of the problem. Because the technology supplier is not providing equipment, his level of liquidated damage support is considerably less than is usually available to utilities. A license is a small part of the overall project and the damages associated with that are very small and insufficient to protect the utility in case the equipment or technology doesn't work as intended by the licensor. Technology suppliers usually only provide process knowledge and, in some cases, equipment recommendations. They leave it up to the purchaser to determine how to implement the technology and engineer, develop, and buy the equipment and hardware necessary to get benefit from the license.

Another area we are finding extremely difficult is confidentiality. The licensors' primary business is that of supplying technology. They need the license to protect their livelihood. They generally have no desire to supply hardware, and only get involved in certain instances where they can become an owner of the plant. For electric utilities, this is not often possible.

Therefore, when the licensor supplies his technology a secrecy agreement is normally required. This significantly compounds the "normal" way of conducting of business for a utility.

Administration of these agreements demands continuous management attention. Even simple things, like buying minor components, usually results in significant requirements for subsupplier secrecy agreements and negotiations of these agreements with the technology vendors. It is our experience and opinion that the technology vendors are very difficult to negotiate with due to their requirements for secrecy.

These confidentiality agreements extend down not only to the A/E and to the suppliers, but also subsuppliers. This could have a potential for utilities not wanting to fight the battle to implement a new technology. It would be a shame if the industry rejected gasification due to the new and difficult requirements of confidentiality for something which may not be readily and totally disclosed to the utility. It also increases the overall costs and duration of the project due to the fact that attorneys now have to get involved in negotiating for simple purchases. This has the potential for impacting project costs in the range of, pick a number, 5%, 10%, 15%, or 20%. For the technology to be successful, the technology licensors and the utilities will have to be flexible and reach a common understanding in the very near future.

Other opportunities that are seen, are for turnkey parts of the IGCC project. We are proceeding in our project to buy the air separation unit on a turnkey basis. That means they will engineer, procure, install, and start-up the air plant. There was even a proposal for them to operate the air plant and sell us air "over the fence". This alternative will continue to be evaluated by utilities as they look for ways to reduce the overall capital costs and make the IGCC system more competitive in the open market.

It is suggested that technology vendors could ease the overall burden and costs if they were to approach this technology similar to the way the boiler manufacturers used to do with the utility industry. Utilities would go to one person to buy the technology, equipment, and the guarantees. This certainly eased the burden for the utilities, but admittedly put more risk on the licensors

or vendors. If technology suppliers wish to participate in the utility market, they should seriously consider this, or some alternative option, attractive to utilities.

The bottom line is that both utility and technology suppliers must maintain flexibility and open mindedness in their approach to this new business. Both sides will have to change their way of normally doing business in order for the IGCC concept to proceed successfully. We have developed ways to bridge this gap for our project but it has been very difficult and slow in coming. Technology suppliers have been very reluctant to change their way of doing business. Most of them have been doing business this way for the past forty or fifty years and change is very difficult for them. To reap the rewards for the massive utility industry market that is out there, they must be willing to make this compromise.

Tampa Electric had to learn this flexibility. We have seen that there are many different ways to conceive, design, install, and operate a plant. One of these is to physically relocate our production engineering team to our A/E's offices to expedite the overall design and review process. It normally took several weeks to process a single drawing where the vendor would prepare the drawing, send it to the A/E, the A/E would review it in his offices and send it back. It would be sent to the client for final approval. For our project, we have relocated our personnel to the A/E offices to simultaneously review and approve concepts, specifications, and drawings as they are being prepared rather than sequentially. We expect this to pay significant monetary and schedule gains. We understand this may be standard for refinery and other types of projects, but it was a major philosophy change for us.

To achieve wide success for utilities, suppliers, and A/E's we must all accept the challenge in recognizing that flexibility and ingenuity applied to both technical and business issues will be the key to successful commercialization of any new concept, specifically coal gasification IGCC. We feel that we now have achieved this success with our partners on our project and invite you to pursue our and other similar and novel approaches to realize the tremendous benefits associated with IGCC Technology.

CLEAN COAL POWER
at
TOMS CREEK

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Atlanta, September 7-9, 1993

CLEAN COAL AT TOMS CREEK

INTRODUCTION

On October 20, 1992 the US Department of Energy (DOE), through the Morgantown Energy Technology Center, entered into Cooperative Agreement DE-FC-21-93MC92444 with TAMCO Power Partners to implement the Toms Creek Integrated Gasification Combined - Cycle Demonstration Project.

The process design is proceeding as scheduled, and a draft Environmental Information Volume has been produced. The overall project schedule, however, may have to be adjusted when the Power Sales Agreement has been finalized.

TECHNOLOGY OVERVIEW

Coal gas is produced in an air-blown fluidized bed gasifier using U-GAS® technology. Most of the sulfur is captured by dolomite which is fed to the gasifier for that purpose. The balance of the sulfur and the particulate matter entrained by the coal gas are controlled by the hot gas clean-up system which is located between the gasifier and the gas turbine generator. Electrical power is generated from the combustion of the clean hot coal gas in a gas turbine generator. Power also is generated from the steam produced in a heat recovery steam generator by cooling the hot combustion gases coming from the gas turbine generator.

When coal gas is unavailable, power generation will be maintained by firing the gas turbine generator with natural gas.

The contaminants in the exhaust gases leaving the heat recovery steam generator are less than the maximum allowed by applicable standards. The ash and spent dolomite discharged from the gasifier have been shown to be environmentally benign. Essentially there is no water discharge from the plant.

PROJECT OVERVIEW

Project Goals

The primary objective of the Project is to demonstrate an Integrated Coal Gasification Combined Cycle (IGCC) system in a fully commercial setting. The IGCC Technology achieves significant reductions in emissions compared to existing coal-fired facilities. This technology will provide future energy needs in a more efficient and environmentally acceptable manner.

TAMCO will demonstrate the pressurized, air-blown, fluidized bed, integrated coal gasification combined cycle technology. The demonstration includes all major sub-systems: coal feeding; a pressurized, air-blown, fluidized bed gasifier capable of utilizing high sulfur bituminous coal; a gas conditioning system for removing sulfur compounds and particulates from the coal gas at elevated temperatures; an advanced combustion turbine able to utilize low Btu coal gas as fuel; the steam cycle, including a heat recovery steam generator and steam turbine generator; all control systems; and the balance of the plant.

Project Participants

TAMCO Power Partners was organized to provide a rational means for two large, diverse companies to demonstrate, with substantial Government support, the commercial viability of a Clean Coal technology. Each partner owns fifty percent of TAMCO. Together the partners will invest slightly more than half ($\pm 51.7\%$) of the estimated \$196.6 million total project cost. The Government will advance 48.3% of the cost, up to a maximum of \$95.0 million.

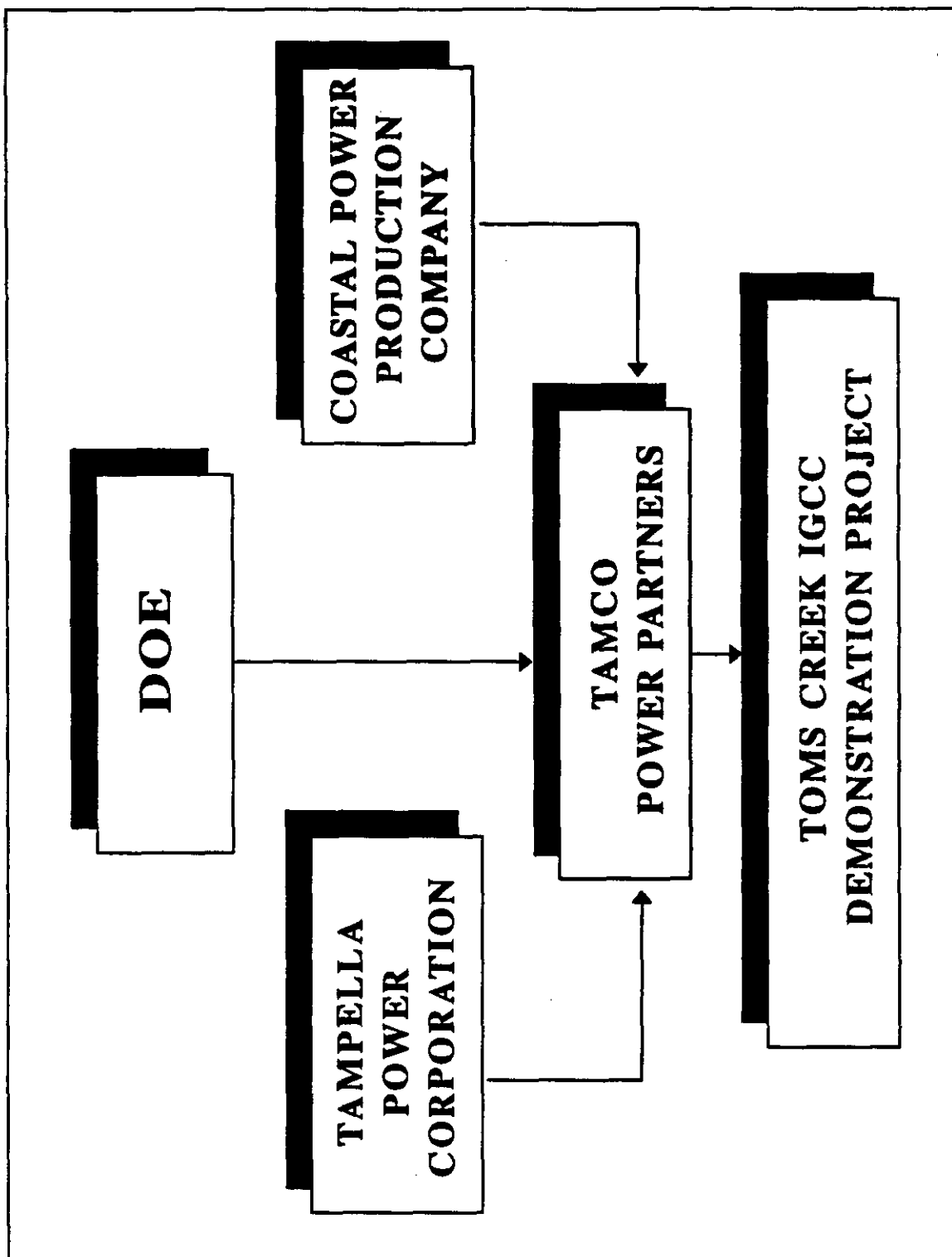


Figure 1. Toms Creek Project Team

TAMCO Power Partners

TAMCO Power Partners is a General Partnership formed under the laws of the State of Delaware by subsidiaries of Tampella Power, Incorporated and The Coastal Corporation. As shown in Figure 1, TAMCO is controlled through Tampella Power Corporation (Williamsport, PA) and Coastal Power Production Company (Roanoke, VA). TAMCO's principal office is co-located with Tampella Power in Williamsport; TAMCO is staffed by Tampella personnel under an Administrative Services Agreement between TAMCO and Tampella.

Coastal Power Production Company

Coastal Power Production Company of Roanoke, VA, is a subsidiary of The Coastal Corporation (NYSE:CGP), a Houston-based energy holding company. Coastal has consolidated assets of more than \$9 billion and subsidiary operations in natural gas transmission and storage; oil and gas exploration and production, refining, and marketing; coal, chemicals, trucking, and independent power production. Coastal operates three natural gas fired combined cycle power plants.

Tampella Power Corporation

Tampella Power Corporation of Williamsport, PA, is a subsidiary of Tampella Power Inc., a major international producer of chemical recovery systems for the pulp and paper industry and power generation systems for industry and utilities. The company's principal markets are in North America, Europe, Southeast Asia, and the former Soviet Union.

Project Responsibilities

Coastal Power is responsible for the design, construction, and operation of the Power Island and the balance of the plant. The Power Island includes the gas turbine generator, the heat recovery steam generator, and the steam turbine generator. Coastal subsidiaries will provide the fuel, ash disposal, and the site for the project.

Tampella Power Corporation is providing the design, construction, and, through the test period, the operation of the Gasification Island. The Gasification Island includes the gasifier, the gasifier feed and discharge systems, and the hot gas clean-up systems. Tampella will conduct the tests during the three year demonstration period. TAMCO Power Partners is being provided with office space and staff by Tampella.

TAMCO Power Partners administers the Cooperative Agreement with DOE.

Project Location

The Demonstration Plant will be built at Toms Creek, next to a coal preparation plant owned by VICC, a Coastal subsidiary located near Coeburn, in Wise County, Virginia.

U-GAS® TECHNOLOGY

The U-GAS® process is a pressurized fluidized bed coal gasification process which produces a low to medium Btu fuel gas from a variety of feedstocks including highly caking, high sulfur, and high ash coals. A simplified diagram of the U-GAS® gasifier is shown in Figure 2.

Coal Preparation and Feeding

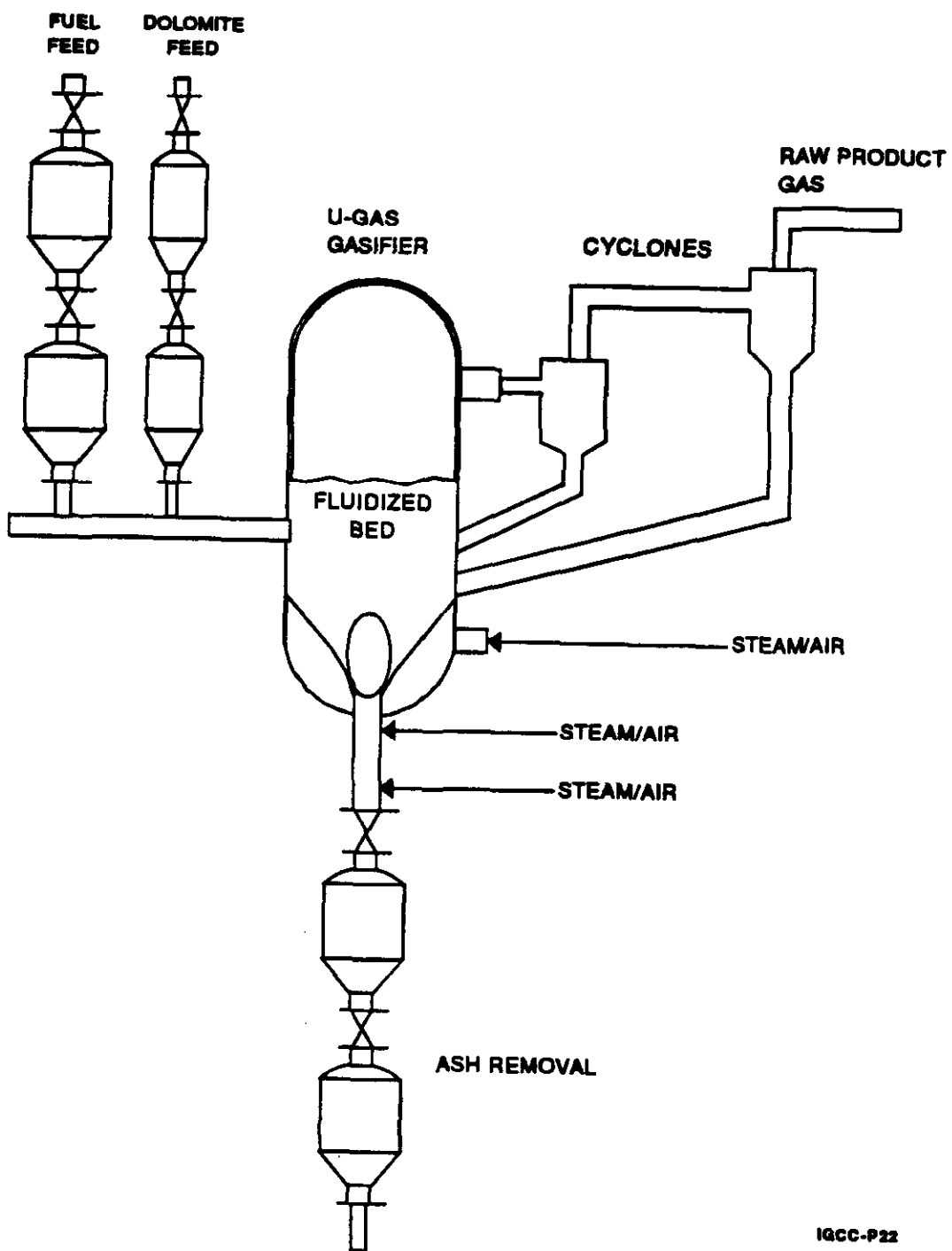
The incoming coal is sized to minus 1/4 inch, plus zero, and dried to a point where surface moisture does not present a handling problem, typically 5% at Toms Creek. Both the coal and dolomite feed systems contain a set of lock hoppers through which the solids feed streams are pressurized, and from which they are transported pneumatically to the gasifier.

Gasification

Within the fluid bed gasifier coal is pyrolyzed, devolatilized, and gasified in a fluidizing medium of air and steam. The bed temperature ranges between 1,650 and 1840°F. The pressure in the gasifier, typically 230 psig, is determined by the pressure drop through the hot gas clean-up systems and the requirements of the gas turbine generator. The temperature within the bed depends on the type of coal and is controlled to maintain non-slagging conditions for the ash. Coal is gasified rapidly in the gasifier and produces a mixture of carbon monoxide, carbon dioxide, methane, hydrogen, water vapor, and about 50% nitrogen; in addition, small quantities of hydrogen sulfide, ammonia, and other trace impurities are evolved. In the reducing environment of the gasifier nearly all of the sulfur present in the coal is converted to hydrogen sulfide before it reacts with the calcium in the dolomite.

Fluidizing gas is introduced into the reactor through the gas distributor plate and through the ash discharge device. In the U-GAS® process, operating conditions in the oxidizing zone are controlled to achieve a low carbon loss which enables a very high 97% overall carbon conversion. The fines elutriated from the gasifier are separated from the product gas in two stages of external cyclones. The fines from both stages are returned to the fluidized bed. The product gas is virtually free of tars and oils due to the relatively high temperature in the upper stage of the gasifier.

U-GAS GASIFIER



IGCC-P22

Figure 2. The U-GAS Process Gasifier

HOT GAS CONTAMINANTS

Sulfur

As shown in Figure 3, desulfurization is accomplished in two stages.

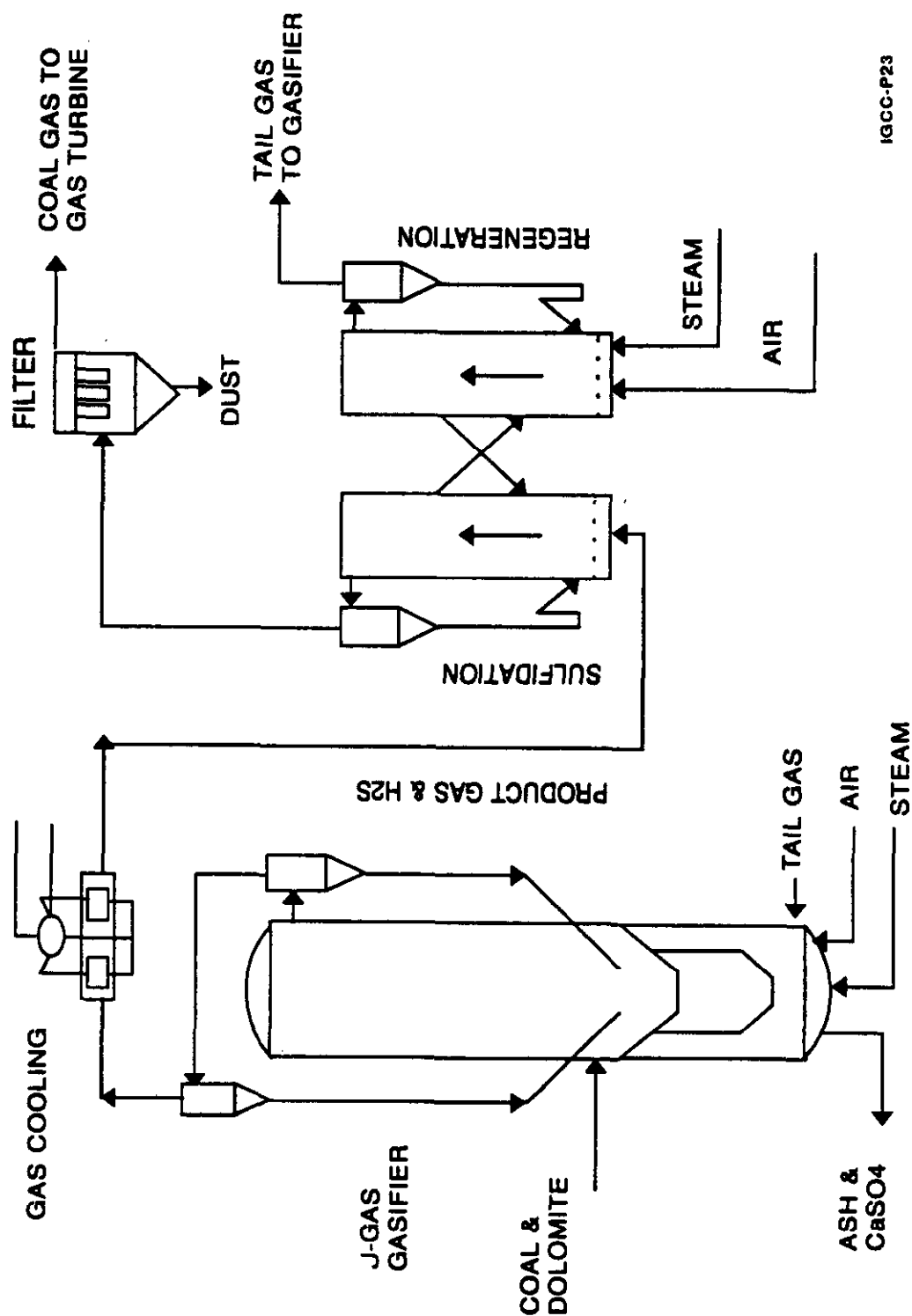
The bulk of sulfur is removed in the fluidized bed gasifier by an equilibrium reaction with the calcium in the dolomite. First, the hydrogen sulfide reacts with calcium carbonate and/or calcium oxide to form calcium sulfide. Then, in the lower portion of the gasifier, the calcium sulfide is oxidized to calcium sulfate. The bottoms product from the gasifier is further stabilized by maintaining the temperature in the lower part of the bed near the fusion temperature of the ash so that controlled particle growth occurs while the particle surfaces acquire a vitreous coating.

The balance of the sulfur is removed from the coal gas in the hot gas clean-up system. A regenerable Zn/Ti-based sorbent is used in the post-gasification sulfur removal process. Tampella Power has developed a two fluidized-bed reactor system. Hot coal gas is contacted with Zn/Ti sorbent in the first reactor, where the sulfur is captured by zinc oxide. Sulfided sorbent is regenerated in the second reactor with air and steam. Steam is added to moderate the temperature of the exothermic reaction. The tail gas is recycled to the gasifier where the sulfur dioxide is captured by the dolomite.

Nitrogen Compounds

The nitrogen in the coal forms molecular nitrogen, ammonia, and hydrogen cyanide during gasification. Some of the ammonia is further decomposed at the high temperatures in the gasifier. To reduce the conversion of ammonia to NO_x in the gas turbine, turbine manufacturers are developing staged combustion processes. Whether a selective catalytic reaction system will be required downstream of the gas turbine to meet NO_x emissions limits has yet to be determined.

SULFUR REMOVAL IN THE IGCC PROCESS



IGCC-P23

Figure 3. Hot Gas Clean-Up

Alkali Metals

Volatile compounds of sodium and potassium which are formed in the gasifier, can participate in hot corrosion and lead to solids build-up in the gas turbine. In Tampella Power's IGCC process, the product gas is cooled to 1,020°F, which is below the dew point of the alkali halides. At this temperature the alkali vapors will condense on the particles that are intercepted by the candle filter.

Particulate Removal

To protect the gas turbine generator from particulate damage, and to meet air emissions limits, a candle shaped ceramic barrier filter will be installed upstream of the turbine inlet valves. Most of the solids elutriated from the gasifier are captured by the two series-mounted external cyclones. The candle filter stops the particulate material leaving the external desulfurizer from reaching the gas turbine or the atmosphere. The ultimate disposition of the material trapped by this filter will be determined following its characterization during pilot plant testing, scheduled for next spring.

"Greenhouse" Gases

The "Greenhouse" gases of concern are carbon dioxide, methane, and nitrous oxide. In the IGCC process, the methane which is produced during gasification is burned in the combustor of the gas turbine. Nitrous oxide does not form in the reducing atmosphere of the gasifier, and its formation is not expected at the high temperatures encountered in the gas turbine combustor. The emission of carbon dioxide cannot be avoided. Carbon dioxide emissions are reduced as the efficiency of power generation is improved. One of the features of the IGCC technology is improved fuel efficiency. The Tom's Creek Plant will have an efficiency of only 40%, later plants will reach 47% efficiency; a reduction of some 10-15% in terms of lower carbon dioxide emissions.

THE DEVELOPMENT OF THE TOMS CREEK IGCC PROCESS

Institute Of Gas Technology

The Toms Creek IGCC Demonstration Project utilizes the U-GAS® coal gasification process, a process which was developed by IGT in a multi-phase program which began in 1974. The heart of the U-GAS® process is an air-blown, pressurized, fluidized bed coal gasifier. The development of this process utilized knowledge from earlier low and medium Btu coal-to-fuel-gas projects at IGT that date back to 1950. The U-GAS® process feasibility was demonstrated initially using metallurgical coke and char as feed to a low-pressure pilot plant. Subsequent tests were made with sub-bituminous and bituminous coals. Eventually process feasibility was proven using high-sulfur caking bituminous coals. Necessary environmental data were collected and the reactor dynamic responses were investigated. Process data were developed for the scale-up and design of a commercial plant.

The original pilot plant had an operating pressure of 50 psig. A high-pressure process development unit was built in 1984 and data were obtained for the gasification of sub-bituminous coal and lignite at pressures up to 450 psig. Test runs included the use of steam and air to gasify bituminous coal with in-situ desulfurization. In support of demonstration plant designs, several tests also conducted in the low-pressure pilot plant with different design feedstocks.

The IGT pilot plants have been operated for 12,000 hours on a variety of feeds including highly caking, high ash, and high sulfur coals. The process has demonstrated its capability to gasify and produce ash agglomerates from raw coal. The operation of the pilot plant has established process feasibility; has demonstrated safe, repeatable, and reliable operability; and has provided a valuable data base for the design of larger plants such as the Toms Creek IGCC Demonstration Project. Successful demonstration at Toms Creek will move the U-GAS® process into the commercial marketplace.

Tampella Power Corporation

The Toms Creek IGCC Project utilizes a hot gas clean-up system to remove residual sulfur compounds and particulate matter from the gasifier product gas. An integrated pilot plant was built by Tampella in Finland to study gasification and hot gas clean-up. It is diagrammed in Figure 4. Following more than 1,000 operating hours, the plant is being modified to incorporate the external desulfurization system discussed above. The data generated from this 10 MW (t) pilot plant are being used to confirm the theoretical design of the 140 MW (t) demonstration plant at Toms Creek.

TOMS CREEK PROCESS DESCRIPTION

Site and Coal

The greenfield IGCC Project will be sited adjacent to an existing coal preparation plant at Toms Creek. The existing coal refuse disposal facilities will be utilized for ash disposal. Coal for the project will be supplied by the Coastal subsidiary which owns the reserves and operates the preparation plant. The design coal is a high volatile A bituminous, low sulfur (1-1.5% S) coal with a higher heating value of 13,400 Btu/lb. At least two high sulfur coals will be tested during the demonstration period. One test coal will have a free swelling index greater than five.

Process

A flow diagram of the Toms Creek IGCC Demonstration Plant is shown in Figure 5. Crushed and dried coal, 430 tons per day, and dolomite are fed through lock hopper systems to the pressurized fluidized-bed gasifier.

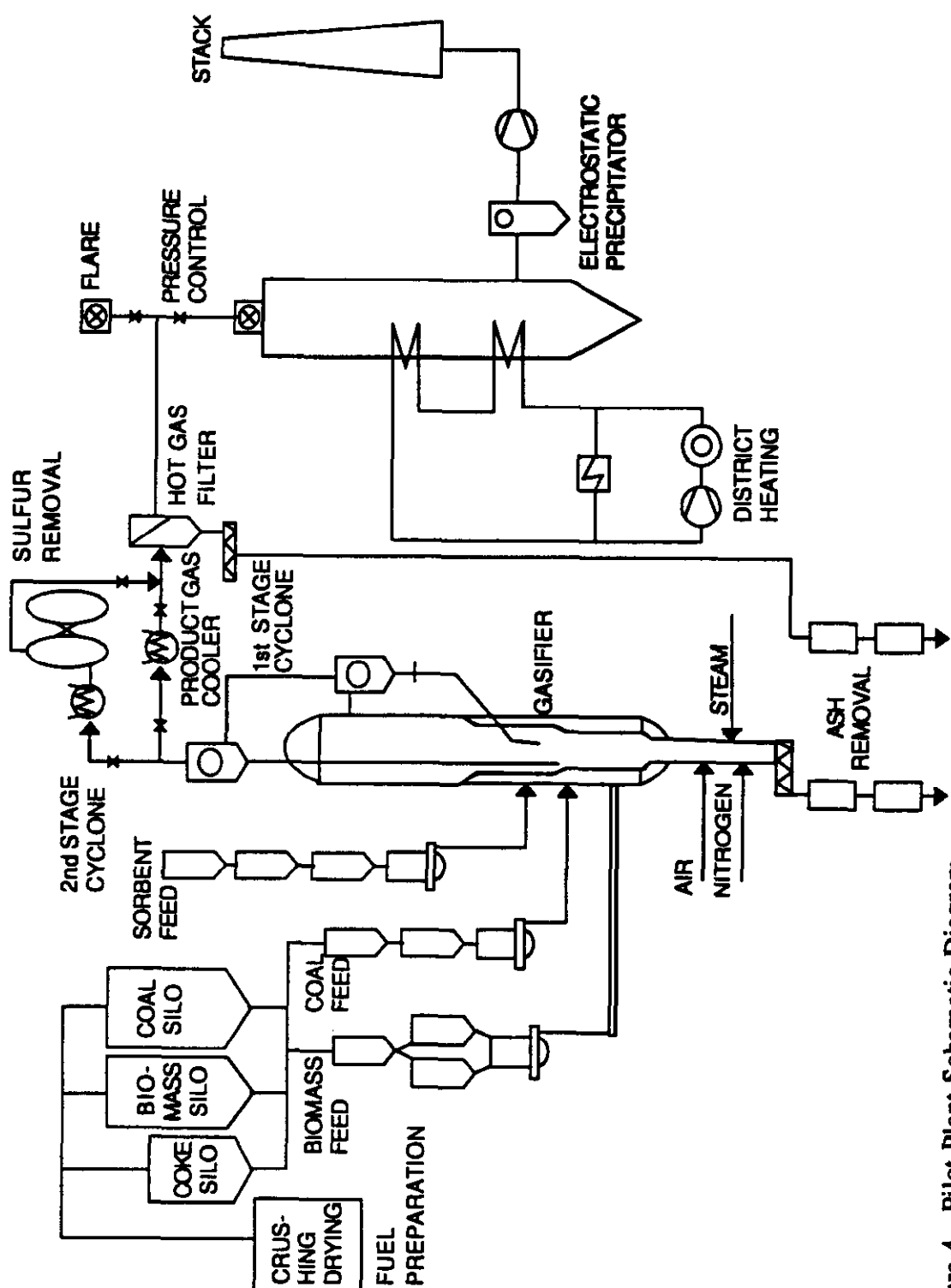


Figure 4. Pilot Plant Schematic Diagram

IGCC-320

Gasification air is supplied by the gas turbine air compressor through a booster compressor; gasification steam is extracted from the steam turbine. Two cyclones are used for particle removal. After exiting the cyclones the product gas is cooled to 1020°F in a fire-tube type evaporating gas cooler, the steam side of which is connected to the heat recovery steam generator (HRSG). The external sulfur removal system is located after the gas cooler. The final clean-up step, the ceramic candle unit, filters the product gas to meet gas turbine and environmental particulate requirements. After filtration the product coal gas, at 130 Btu/scf (lhv), is fed to the gas turbine.

The gas turbine air compressor supplies fluidizing air for the gasifier as well as producing combustion air for the turbine. The gas turbine generator is rated at 38 MW.

The waste heat in the turbine exhaust gases is recovered in a heat recovery steam generator. Some of the steam from the HRSG is used in the gasifier; another portion of the steam is used in the regeneration of the hot gas desulfurization sorbent; while the gas cooler supplies saturated steam to the HRSG. Most of the steam from the HRSG, however, is used by the steam turbine generator which generates an additional 26 MW. The net power output from the Toms Creek IGCC would be 60 MW at ISO conditions, or 55 MW at elevation.

Environmental Performance

The Toms Creek plant does not produce any appreciable process waste water streams.

The only solid waste from the plant is a mixture of ash, spent dolomite and calcium sulfate which is discharged from the bottom of the gasifier. Preliminary tests have shown this material to be a non-hazardous waste which could be utilized in road construction or disposed of in a landfill. Initially the glassified product will be placed in the adjacent coal refuse valley, which is part of the coal preparation facility operation.

Air emissions from the plant are anticipated to be well below current requirements: SO₂ emission of 0.056 lb/MMBtu, NO_x emission of 0.24 lb/MMBtu, and particulate PM₁₀ emission of 0.016 lb/MMBtu.

Schedule & Status

The original project schedule is shown in Figure 6. Construction is scheduled to begin in January 1996 and the three-year test period is scheduled to begin two years later. Because the Power Sales Agreement is not in effect, it will be difficult to start construction as scheduled.

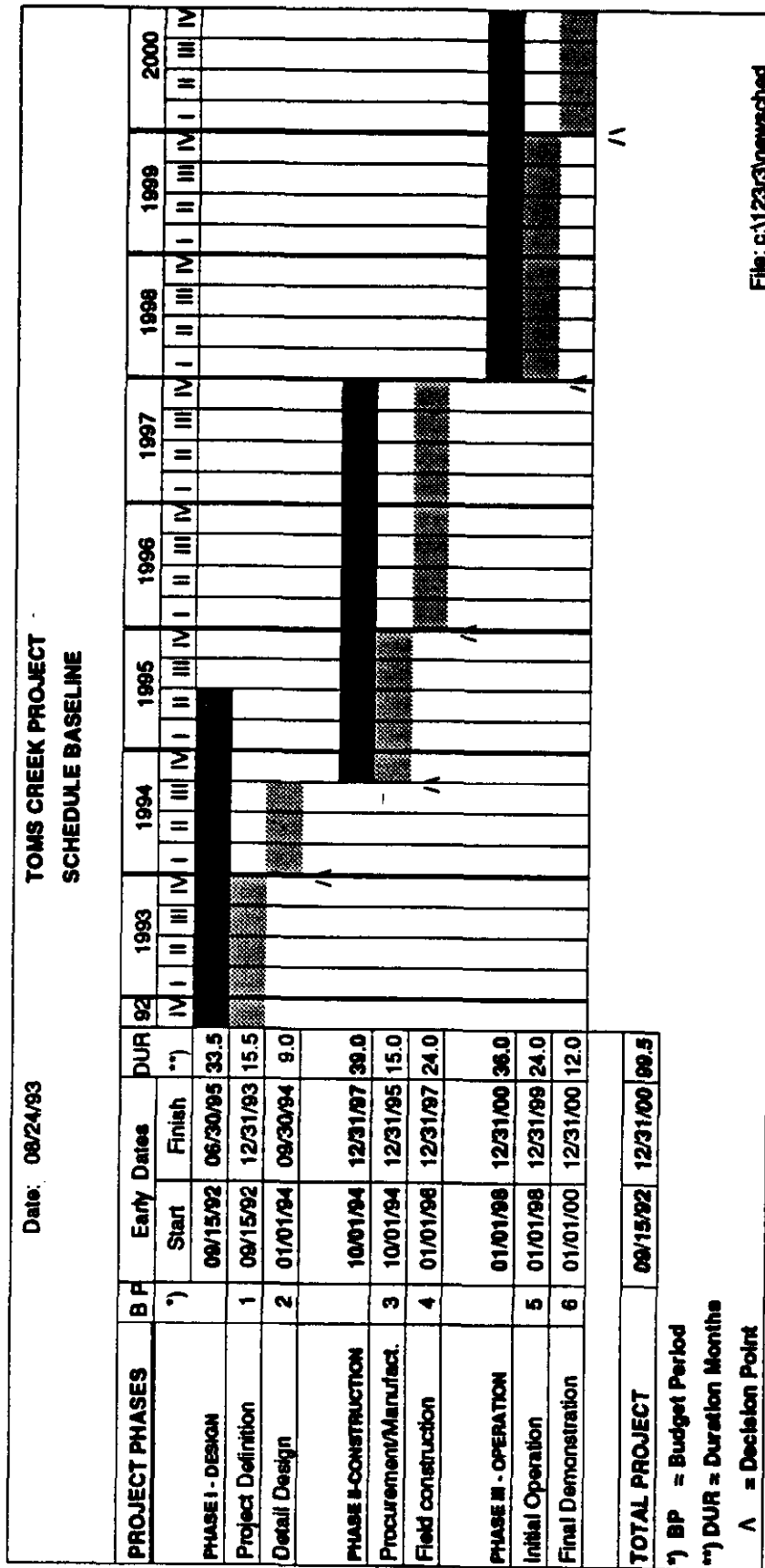


Figure 6. Toms Creek Schedule

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Session 7
Combined NO_x/SO₂
Control Technologies

Co-Chairs:

Richard A. Hargis,

Pittsburgh Energy Technology Center/
U.S. Department of Energy

Gerard G. Elia,

Pittsburgh Energy Technology Center/
U.S. Department of Energy

ENHANCING THE USE OF COAL BY GAS REBURNING AND SORBENT INJECTION

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ABSTRACT

The Gas Reburning-Sorbent Injection (GR-SI) Process was demonstrated on a 71 MWe net tangentially fired boiler at Hennepin, Illinois, and is being demonstrated on a 33 MWe net cyclone-fired boiler at Springfield, Illinois as a Clean Coal Technology Round I demonstration project. The Hennepin demonstration was completed after more than 2,000 hours of successful operation. In long-term demonstration testing at a Ca/S molar ratio of 1.75 and 18 percent gas heat input, 53 percent SO₂ reduction and 67 percent NO_x reduction were achieved without any adverse impacts on boiler performance or electrostatic precipitator performance with flue gas humidification. These achievements exceeded the project goals of 50 and 60 percent, respectively. The CO₂ reduction due to the use of 18 percent natural gas was 8 percent.

INTRODUCTION

The Energy and Environmental Research Corporation (EER) has conducted a project entitled "Enhancing the Use of Coals by Gas Reburning-Sorbent Injection." The goal of the project was to evaluate Gas Reburning-Sorbent Injection (GR-SI) for reduction of emissions of nitrogen oxides (NO_x) and sulfur dioxide (SO₂) from a coal-fired boiler. The specific goal was a reduction in NO_x emissions by 60 percent and SO₂ emissions by 50 percent. The host site for the project is Illinois Power's Hennepin Station Unit 1, which is a 71 MWe (net) tangentially-fired unit designed by Combustion Engineering. The unit was retrofitted with a GR-SI system designed by EER, then underwent start-up activities, optimization testing, and long-term (one year) testing. The project is sponsored by the U.S. Department of Energy (DOE), the Gas Research Institute (GRI), Illinois Power Company, the State of Illinois Department of Energy and Natural Resources (ENR), and City Water, Light, and Power of Springfield, Illinois. This paper describes the performance of the Hennepin Unit 1 GR-SI system, the impacts of GR-SI operation on the unit, and the environmental impacts.

Coal-fired boilers have been known to be major contributors to acid rain precursors, NO_x and SO₂, which are widely believed to have damaged lakes and forests in the northeastern United States and eastern Canada. In response to growing concern regarding pollutant emissions from

coal-fired power plants, DOE initiated the Clean Coal Technology (CCT) program. This EER project is one of several in Round I of the U.S. DOE CCT program. It is one of three carried out simultaneously by EER on a tangentially fired unit (Illinois Power's Hennepin Station Unit 1) and a cyclone-fired unit (Lakeside Station Unit 7 of City Water, Light, and Power in Springfield, Illinois) in CCT Round I, and a wall-fired unit (Cherokee Station Unit 3 of Public

Service of Colorado) under a CCT Round III project. The wall-fired unit has a Gas Reburning-Low NO_x Burner System only.

The project goal was a reduction in NO_x emissions by 60 percent, from an as-found baseline (at Hennepin) of 0.75 lb/MMBtu (323 mg/MJ) to 0.30 lb/MMBtu (129 mg/MJ), and SO_2 emissions by 50 percent, from a baseline of 5.30 lb/MMBtu (2,280 mg/MJ) to 2.65 lb/MMBtu (1,140 mg/MJ). The GR process consists of injection of natural gas, corresponding to 15 to 20 percent of the heat input, at a location above the coal burners to create a fuel-rich zone, resulting in the formation of hydrocarbon fragments and radicals which reduce NO_x , formed in the coal zone, to molecular nitrogen. Overfire air is injected at a higher elevation to burn out the fuel combustibles under fuel lean conditions. In the SI process, a calcium-based sorbent, such as calcium hydroxide [$\text{Ca}(\text{OH})_2$], is injected into the upper furnace to react with flue gas SO_2 , resulting in formation of calcium sulfate (CaSO_4) and calcium sulfite (CaSO_3). These solids are carried from the boiler and captured with the fly-ash in the particulate collection device.

The project began in June 1987 and was carried out in three phases:

- | | |
|-----------|---|
| Phase I | Design and Permitting |
| Phase II | Construction and Start-Up |
| Phase III | Operation, Data Collection, and Reporting |

This paper describes the Phase III test program and its results.

The Test Program

The Boiler and Process Systems

Figure 1 shows an overview of the GR-SI and humidification systems installed on this unit. Details of the gas, overfire air, and sorbent injection locations are shown in Figure 2.

The Test Program Objectives and Schedules

The test program was quite detailed in scope in order to evaluate the many parameters which affect the process performance and its impact on the boiler system (Figure 3). Figure 4 indicates the measurements which were carried out during this program. The parametric test results have been discussed in an earlier paper^[1] and will be detailed in the final report now in preparation. Therefore, the emphasis here will be on the long-term demonstration testing results and on the work with promoted sorbents, which have performed better than the standard hydrated lime. Several references on Gas Reburning-Sorbent Injection [2-12] are available.

Long-Term Emissions Performance

The parametric testing data were analyzed to establish the operating conditions under which the program target emissions would be achieved. Several parameters were established, including the primary zone stoichiometric ratio, reburning stoichiometric ratio (and corresponding percent gas heat input), and the Ca/S molar ratio. To achieve the target NO_x and SO₂ emissions while maintaining low CO emissions, the nominal operating conditions for the long-term demonstration tests were established as:

Coal Zone Stoichiometric Ratio	= 1.10
Reburning Zone Stoichiometric Ratio	= 0.90
Burnout Zone Stoichiometric Ratio	= 1.20
Gas Heat Input	= 18%
Ca/S Molar Ratio	= 1.75

GR-SI long-term demonstration tests were carried out from January 10, 1992, to October 20, 1992, to verify the system performance over an extended period. The unit was operated at constant loads and with the system under dispatch operation where the load was varied to meet the plant power output requirement. With the system under dispatch, the load fluctuated over a wide range, in some cases, from a low of 40 MWe to the maximum load of 75 MWe, and in

other cases, over a more narrow range. Over the long-term demonstration test series, the following operating parameters were in close agreement with the desired settings above:

Primary Zone Stoichiometric Ratio	= 1.09
Reburning Zone Stoichiometric Ratio	= 0.90
Exit Zone Stoichiometric Ratio	= 1.21
Gas Heat Input	= 18.2%
Ca/S Molar Ratio	= 1.76

Over the long-term demonstration period, the average gross power output was 62 MWe. Linwood hydrated lime was used throughout these tests except for a few days when Marblehead lime was used.

For the long-term demonstration testing, the average NO_x reduction of 67.3 percent and the average SO_2 reduction of 52.6 percent correspond to emissions of 0.246 lb NO_x /MMBtu (106 mg/MJ) and 2.51 lb SO_2 /MMBtu (1,080 mg/MJ) as shown in Figure 5. The reductions are calculated from the baseline emissions of 0.75 lb NO_x /MMBtu (323 mg/MJ) and 5.30 lb SO_2 /MMBtu (2,280 mg/MJ). Emissions of CO were below 50 ppm (at 3 percent O_2) in many cases but were higher during operation at low load. Emissions of CO averaged 57 ppm over all GR-SI tests. Hydrocarbon emissions were generally very low, averaging 1.9 ppm with a range of 0.1 to 18.2 ppm (at 3 percent O_2). A significant reduction in CO_2 emissions was also measured. This is due to partial replacement of coal with natural gas having a lower C/H ratio. This cofiring with 18% natural gas results in a theoretical CO_2 emissions reduction of 7.9 percent from the coal-fired baseline level.

Emissions of N_2O were of concern due to its potential impact on the atmosphere. N_2O is believed to contribute to the global-warming greenhouse effect and impact the ozone concentration in the stratosphere. Due to these concerns, emissions of N_2O were measured during GR, GR-SI, and SI testing. The N_2O emissions during GR-SI operation ranged from 0.5 to 3.2 ppm. The emissions during baseline testing averaged 0.8 ppm, and during SI testing, the

N_2O emissions were in the 1.0 to 1.3 ppm range. These levels are very low, indicating that GR-SI may be operated without unacceptably high N_2O emissions.

Long-Term Thermal Performance

GR-SI was expected to have a minor impact on the thermal performance and operation of Hennepin Unit 1. This section summarizes the thermal performance data associated with GR-SI over the long-term demonstration test period. Extensive data were collected and evaluated to ensure that the Hennepin Unit operated at its rated capacity with proper steam temperatures and pressures. Furthermore, it was important to verify that no adverse impacts would result due to GR-SI operation.

During the design phase, two important goals were established. The first goal was that Hennepin Unit 1 would produce steam at its rated capacity during GR-SI operation, albeit with slightly lower thermal efficiency and some minor changes in heat absorption profiles. The second goal was that steam temperatures could be controlled to their design values using the existing steam temperature control systems. These conclusions were based on performance predictions for nominal GR-SI conditions. During the long-term test program, these predictions were validated over a wide range of boiler loads.

Various thermal performance parameters were collected or calculated on the EER's PC-based on-line Boiler Performance Monitoring System. The database that was established included the following thermal performance parameters:

- Steam production, temperature, and pressure,
- Steam attemperation,
- Gas side temperatures,
- Heat transfer to steam,
- Cleanliness factors,
- Boiler efficiencies, and
- Boiler heat rate.

Table 1 summarizes the thermal performance of the Hennepin unit during the long-term demonstration program for Gas Reburning-Sorbent Injection operation. Since the demonstration was conducted during dispatch control, the data are summarized for low, mid, and high load. In addition, results are compared to modeled predictions to evaluate the validity of the design methodology.

Humidification

Sorbent injection systems often impact ESP performance due to an increase in particulate loading and increased fly-ash resistivity. Typically, sorbent injection may double or triple particulate loading. In addition, the presence of spent sorbent may increase fly-ash resistivity by as much as 2 orders of magnitude. The particulate size distribution may also decrease. The increase in fly-ash resistivity may result in degradation in the ESP electric field power and therefore result in a reduction in collection efficiency. The flue gas humidification system was designed to reduce the gas temperature to within 70°F (39°C) of adiabatic saturation by injection of atomized water in the duct between the air heater and the ESP. Dual fluid Delavan nozzles were used. Figure 6 shows the essential parts of the humidification duct design. The design residence time is approximately 2 seconds at full load. Five screw conveyors were provided to move the ash out of the duct into the plant sluicing system. Adjustable turning vanes and a perforated plate are used to smooth out the flow pattern of the flue gas entering the humidification zone. The humidification system typically operated at the much higher approach to saturation of 120°F (67°C). With flue gas humidification, ESP collection efficiencies greater than 99.8 percent and particulate emissions less than 0.025 lb/MMBtu (11 mg/MJ) were measured even with an increase

in inlet particulate loadings. These are comparable to the measured baseline emissions of less than 0.035 lb/MMBtu (15 mg/MJ) and collection efficiencies greater than 99.5 percent. This has permitted operation with sorbent injection and continued adherence to the regulatory limit of 0.10 lb particulate matter/MMBtu (43 mg/MJ).

Fly-Ash Resistivity

In-situ measurements were conducted at the ESP inlet ports using a point-to-plane probe. The method entails creating an electric field between an electrode and a grounded collecting plate. As the flue gas passes between the electrode and the collecting plate, a V-I curve is obtained, first with a "clean" plate and then with a "dirty" plate. The resistivity is calculated from the difference of the two V-I curves and the measurement of the layer of the fly-ash on the "dirty" plate.

Baseline and gas reburning tests showed fly-ash resistivity results in the order of the mid 10^{10} ohm-cm at temperatures of about 330°F (165°C), which is typical of fly-ash from bituminous coal with a sulfur content of about 3 percent. For the GR-SI tests, the measurements indicated resistivities ranging from 6×10^{10} ohm-cm at 180°F (82°C) to 6×10^{11} ohm-cm at 300°F (149°C). The in-situ resistivities measured by the V-I method at 70 MWe are shown in Figure 7. The resistivities quoted in the mid 10^{11} ohm-cm at the higher temperatures are lower than expected. It could be possible that the unreacted hydrated lime helped to moderate the fly-ash resistivity.

Good to excellent precipitation of the ash-sorbent mixture can be expected at 6×10^{10} ohm-cm. However, resistivities higher than 6×10^{12} ohm-cm at the higher temperature will result in lower ESP operating voltages due to possible back corona and/or premature sparkover. The increased sparkover and resulting reduced operating voltage will also reduce current input into the ESP fields by a factor of 6 to 10 at the 6×10^{11} ohm-cm resistivity.

Extended Operation

The Hennepin Unit 1 is a cycling unit which typically operates about 12-14 hours per day. After optimizing the sootblowing scenario, several extended GR-SI runs were carried out. Prior to these runs, the system had operated for 8 hours per day or less. One of these extended runs was for 55 hours at variable loads (45-62 MWe dispatch controlled). No difficulties were encountered with the ESP performance. A more rigorous test was a 32-hour run at full load. This required sootblowing for about 84 percent of the operating time to control the furnace exit temperature such that the humidification system could properly regulate the gas temperature entering the ESP. Figure 8 shows the thermal performance of the boiler during this 32-hour run. These extended runs demonstrated that GR-SI is a technically feasible NO_x/SO_2 control process for a utility boiler of this type.

Promoted Sorbent Tests

Following the completion of the long-term tests, three specially prepared sorbents were tested. Two were manufactured by EER at the California test site. They contained proprietary additives to increase their reactivity toward SO_2 . In the section below, they are referred to as PromiSORB™ A and B. The other special sorbent was developed by the Illinois State Geological Survey. It is a high surface area hydrated lime (HSAHL) which uses alcohol to form a material which, upon its evacuation, gives rise to a much higher than normal surface area per unit weight than the atmospherically hydrated limes. The system was unmodified even though the densities of these materials were somewhat lower than the standard hydrated lime.

All test results discussed below are without gas reburning although a number of GR-SI tests were also carried out. Figure 9 shows that the SO_2 capture at the nominal 1.75 Ca/S molar ratio was 66 percent for PromiSORB™ B, 59 percent for HSAHL, 54 percent for PromiSORB™ A, and 42 percent for Linwood lime. The data on PromiSORB™ B are more scattered than the others, suggesting a nonuniform composition. At a 2.6 Ca/S, the PromiSORB™ B gave 80 percent SO_2 reduction. The calcium utilization plots shown in Figure 10 show a similar pattern at the nominal

1.75 Ca/S: 38 percent for PromiSORB™ B, 34 percent for HSAHL, 31 percent for PromiSORB™ A, and 24 percent for Linwood.

The optimum temperatures for the promoted materials are somewhat lower than that for the standard hydrated lime and utilization was found to increase at low loads and with higher furnace oxygen concentration. PromiSORB™ A also improved NO_x reduction by 15-35 percent, depending on test conditions, owing to a proprietary additive in the sorbent.

The very low density of the HSAHL prevented testing Ca/S ratios above 1.8. The Fuller-Kinyon screw pump was designed for 30-35 lbs./cu.ft. (0.48-0.56 g/cm³) material, compared to the HSAHL density of 20 lbs/cu. ft. (0.32 g/cm³).

All of these sorbents showed encouraging results and the potential for further improved performance with optimized system design for their somewhat different physical properties.

Lakeside GR-SI Project Status

This project uses the same basic process as the Hennepin unit. The equipment is installed on a 33 MWe cyclone-fired pressurized boiler. Construction and start-up are complete, and the testing phase has just begun. Initial GR and SI tests indicate that the 60 percent NO_x and 50 percent SO₂ reduction goals can be achieved in the cyclone-fired boiler like in the tangentially-fired boiler.

SUMMARY

1. Gas Reburning, Sorbent Injection, and Gas Reburning-Sorbent Injection technologies have been successfully demonstrated on a 71 MWe (net) tangentially fired boiler at Hennepin, Illinois. A similar project is being conducted on a 33 MWe (net) cyclone-fired boiler at Springfield, Illinois.

2. During the period of the long-term demonstration, Gas Reburning-Sorbent Injection at a nominal natural gas heat input of 18 percent and a nominal Ca/S molar ratio of 1.75 achieved an average NO_x reduction of 67 percent and an average SO₂ reduction of 53 percent. These levels of emission reductions have exceeded their respective design goals of 60 percent and 50 percent. Illinois Power, the host company, has decided to retain the Gas Reburning system.
3. The Gas Reburning-Sorbent Injection technology also reduced CO₂ emissions by 8 percent.
4. Flue gas humidification is effective in enhancing the electrostatic precipitator performance during sorbent injection.
5. Three promoted sorbents including PromiSORB™ B, High Surface Area Hydrated Lime, and PromiSORB™ A have demonstrated improved performance over regular hydrated lime in SO₂ capture and calcium utilization.
6. Gas Reburning, Sorbent Injection, and Gas Reburning-Sorbent Injection are ready for commercial applications.

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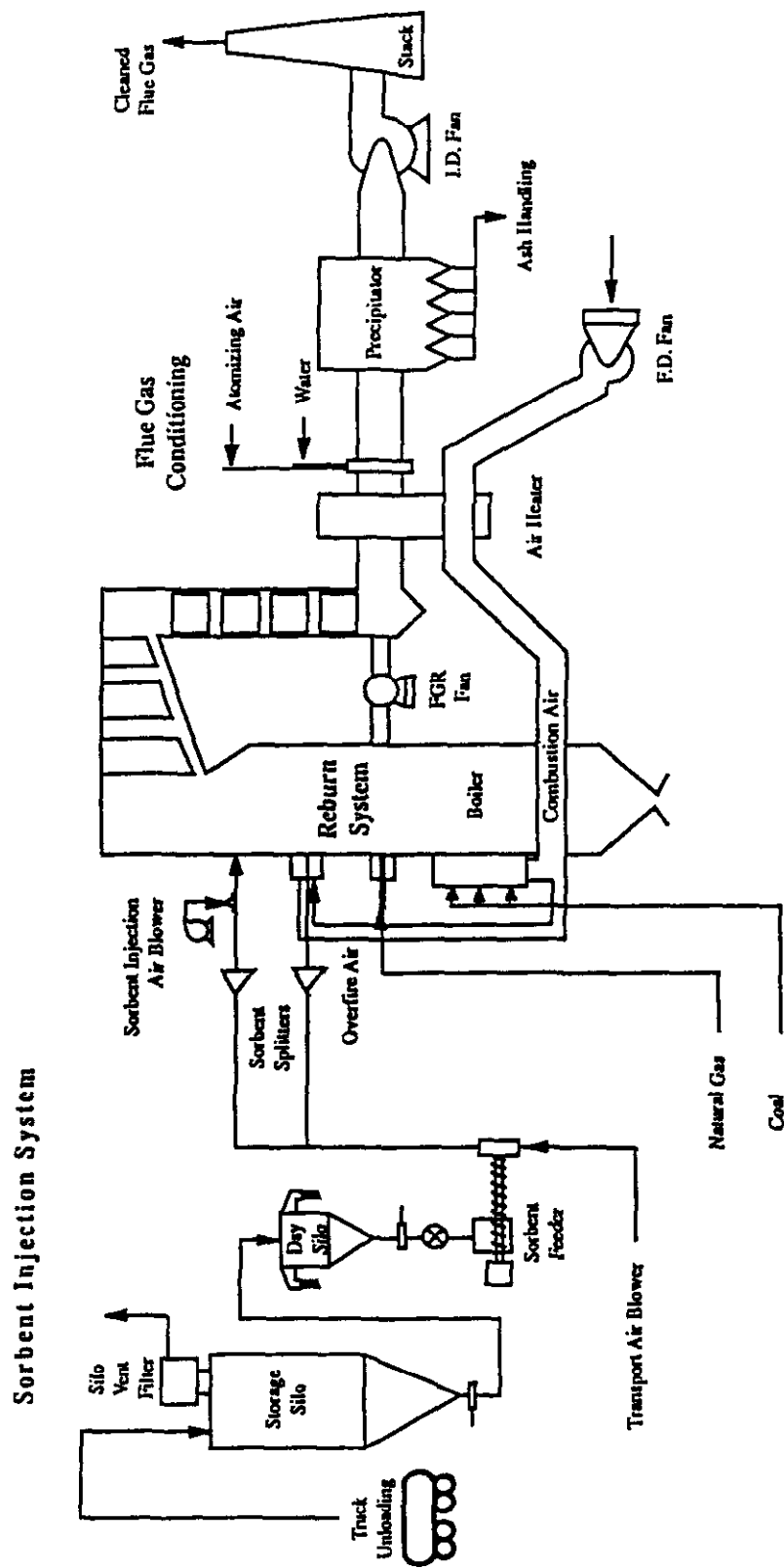


Figure 1. Overview of the GR-SI and humidification systems at Hennepin.

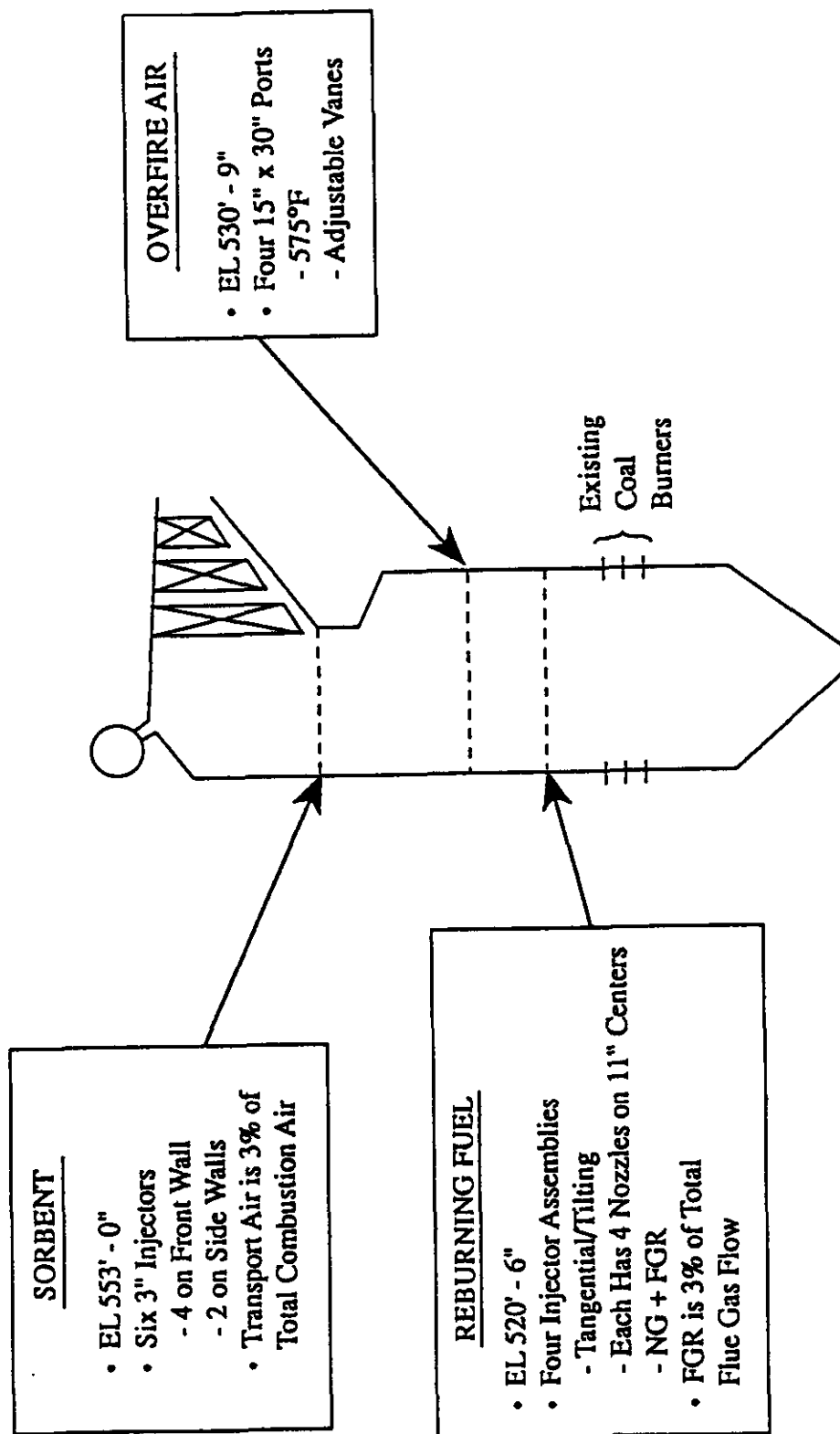


Figure 2. GR-SI injector specification for Hennepin Unit 1.

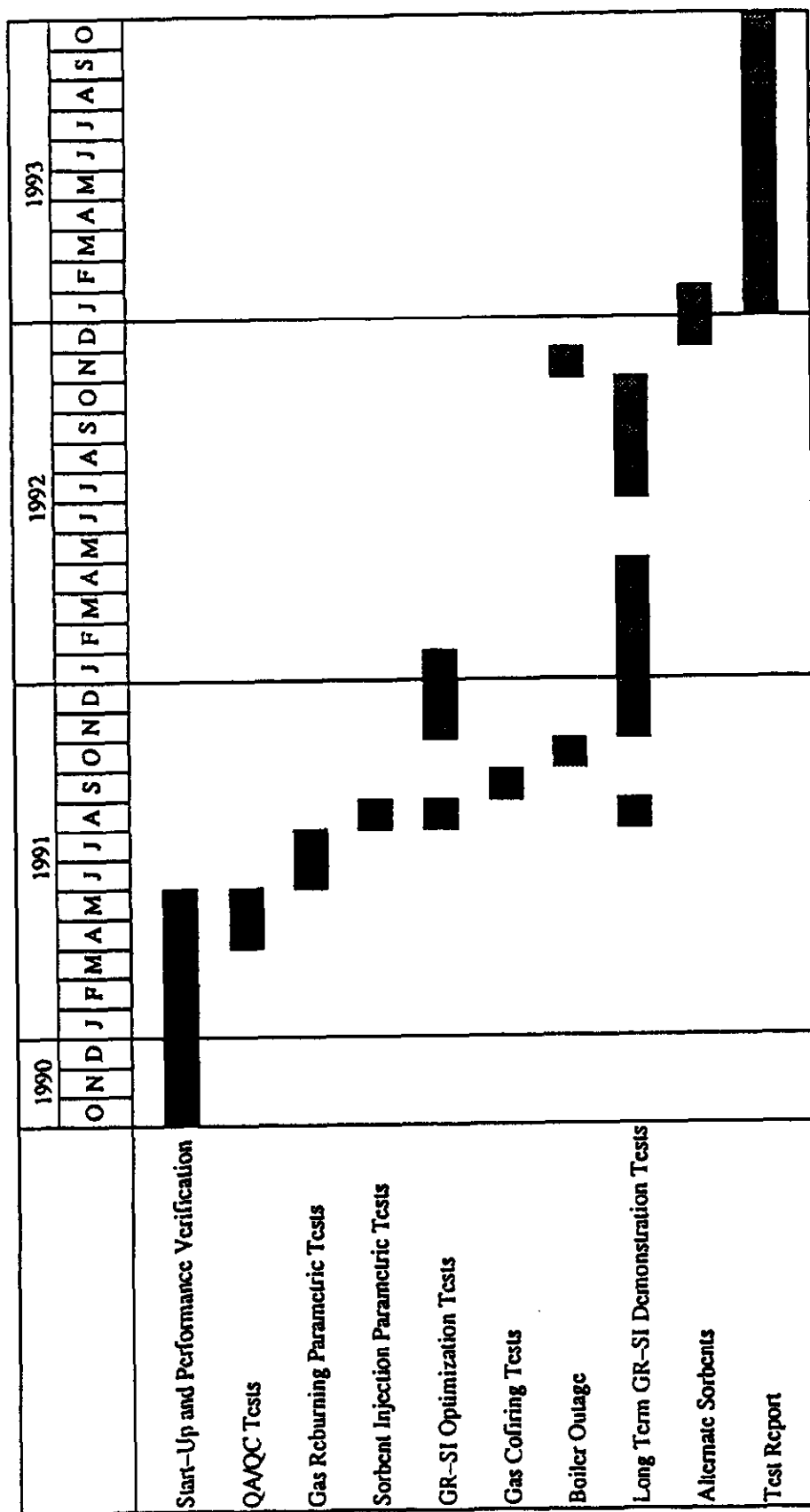


Figure 3. Test schedule for the GR-SI evaluation at Hennepin Unit 1.

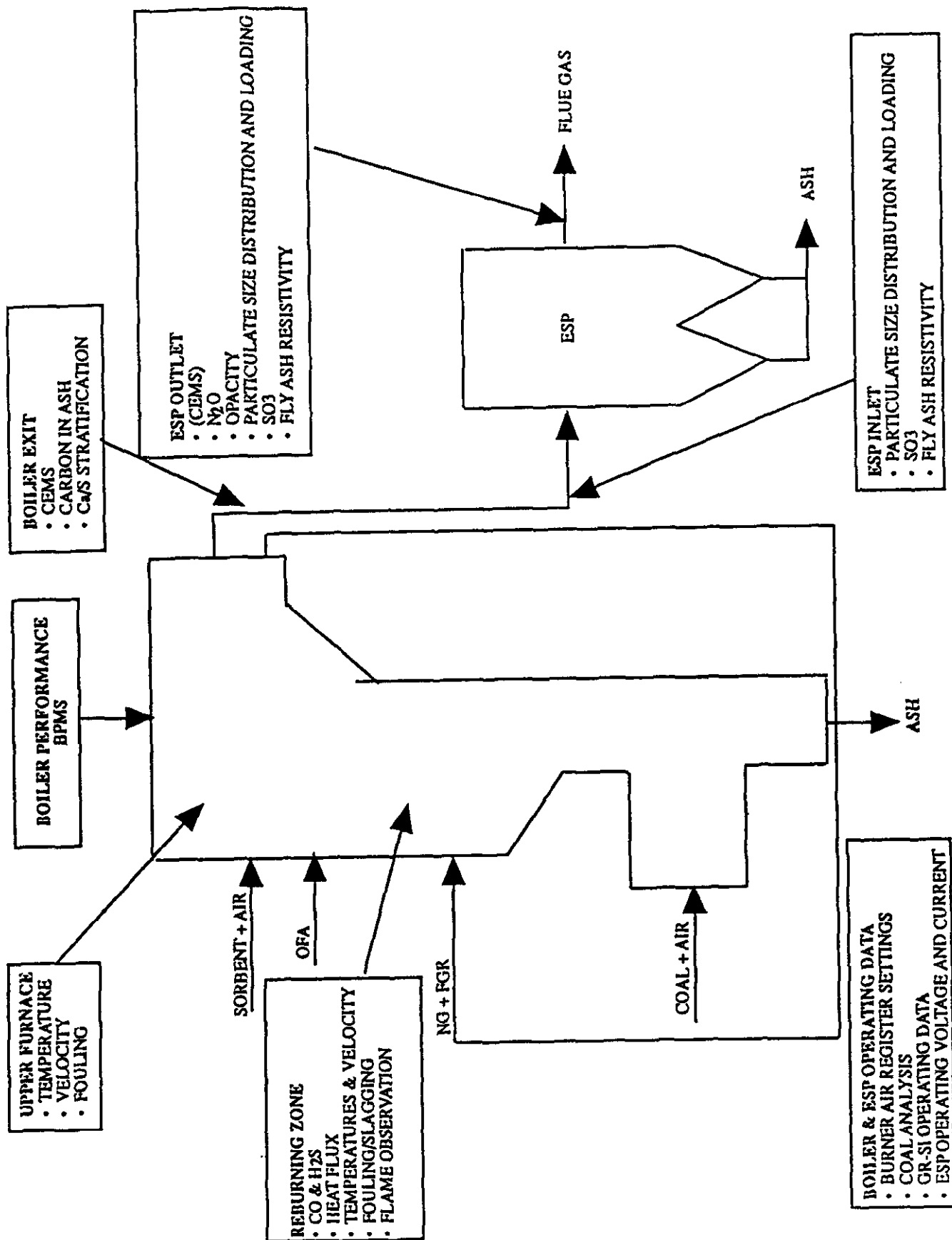


Figure 4 Measurement overview.

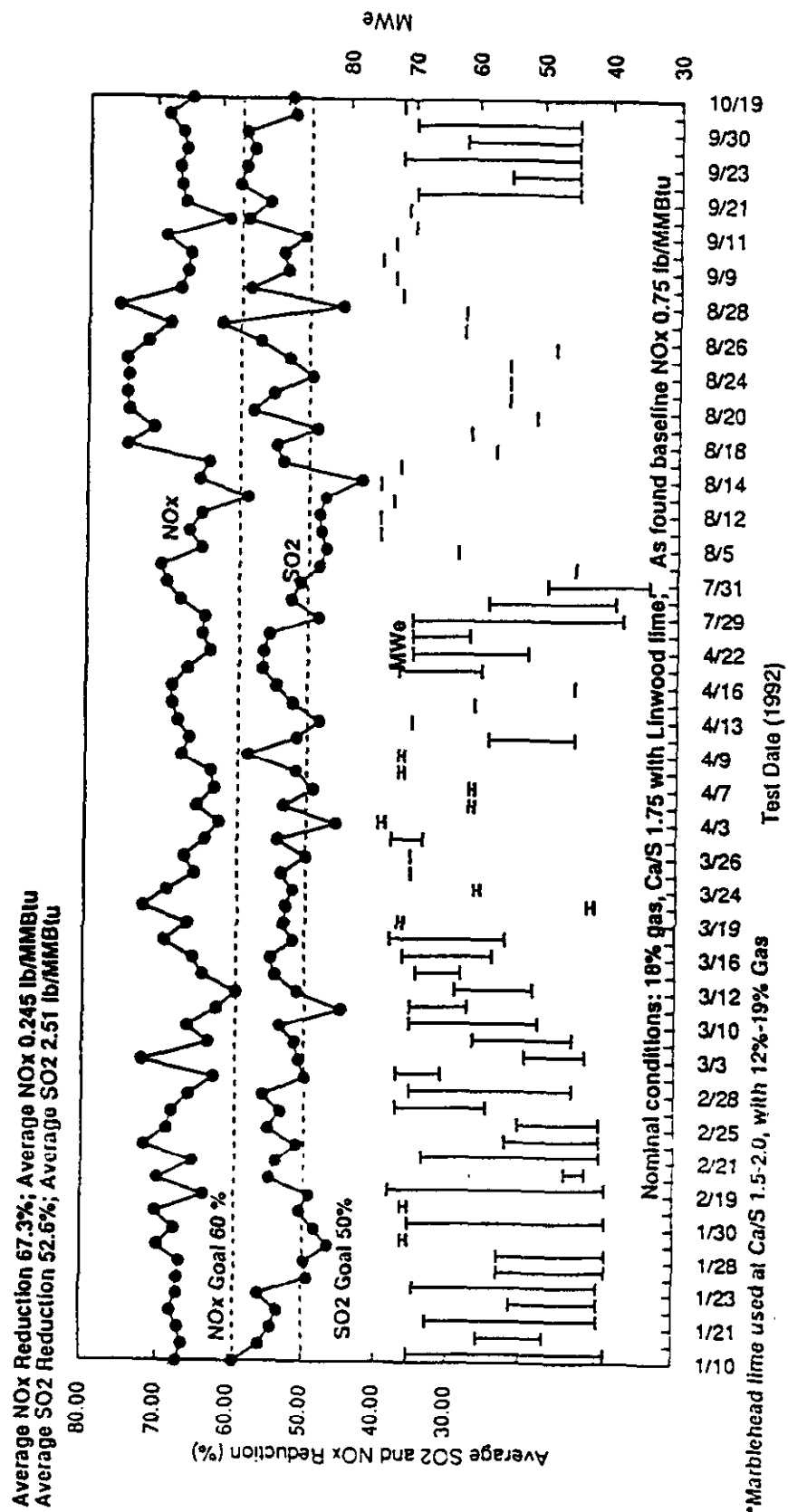


Figure 5. Emissions of NO_x and SO₂ from long-term GR-SI testing.

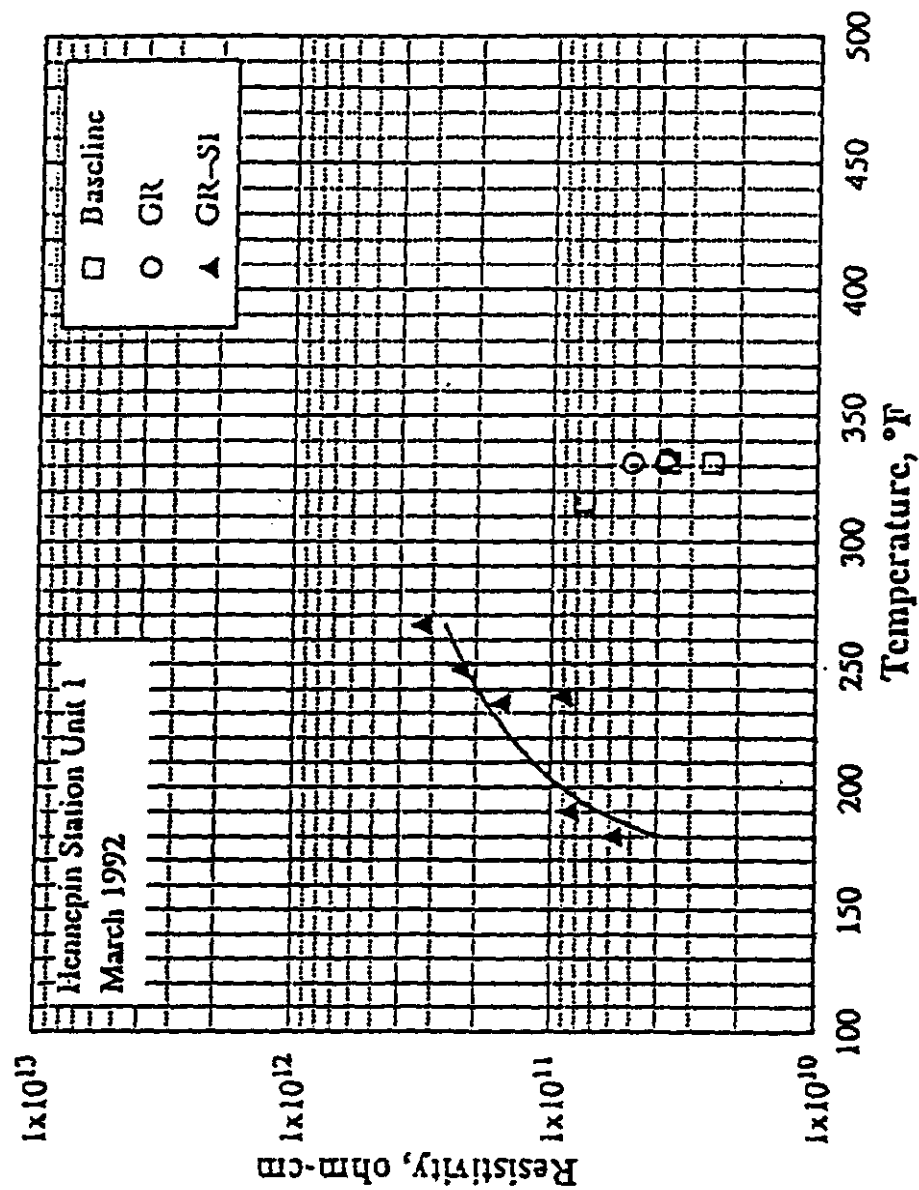


Figure 7. In-situ resistivity measurements by the V-I method at 70 MWc.

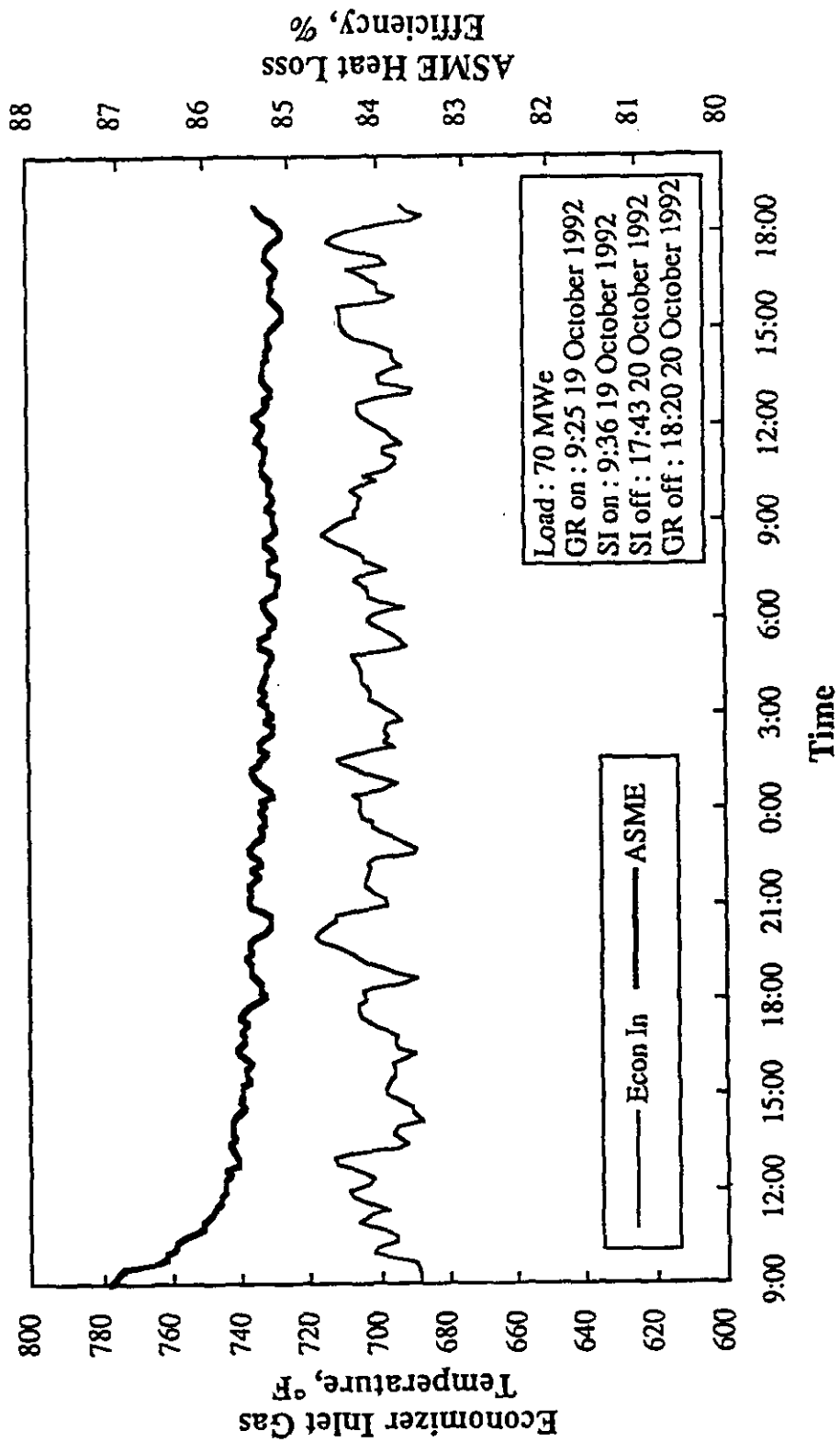
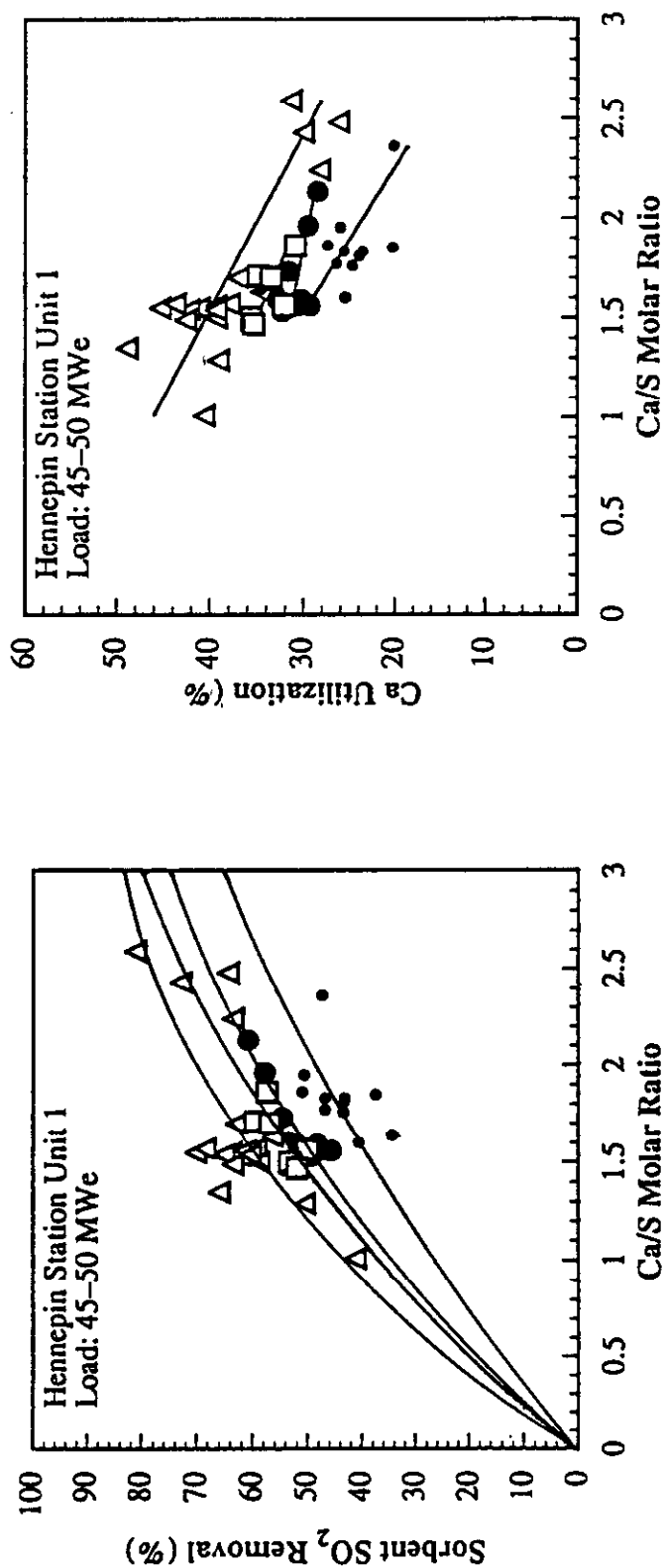


Figure 8. Economizer inlet gas temperature and boiler efficiency during 32 hour GR-SI test run.



Figures 9 and 10. SO₂ removal and calcium utilization with promoted sorbents vs. standard hydrated lime.

TABLE 1. SUMMARY OF GR-SI LONG-TERM THERMAL PERFORMANCE

Thermal Parameters	45 MWe	60 MWe	70 MWe	Predicted*
Process Variables				
Percent Gas Heat Input	19	18	17	18
Ca/S Molar Ratio	1.79	1.79	1.80	2.00
Exit Plant O ₂ (%)	3.40	3.06	2.84	2.80
Steam Side Temperatures (°F/°C)				
Exit Secondary Superheater	980/527	989/532	994/534	1,005/541
Exit Primary Superheater	827/442	861/461	883/473	868/464
Exit High Temp Reheater	930/499	964/518	987/531	1,005/541
SH Steam Attenuation (lb/hr)	3,863	9,215	12,783	16,500
(kg/hr)	1,752	4,180	5,798	7,484
Heat Transfer (10⁶ Btu/hr) (GJ/hr)				
Furnace Waterwalls	215/227	293/309	344/363	349/368
Secondary Superheater	37/39	47/50	54/57	61/64
Reheater	43/45	57/60	67/71	74/78
Primary Superheater	72/76	107/113	129/136	133/140
Economizer	16/17	20/21	23/24	29/31
Cleanliness Factors				
Furnace	1.083	1.058	1.042	N.D.#
Secondary Superheater	0.903	0.911	0.916	N.D.
Reheater	0.921	0.954	0.977	N.D.
Primary Superheater	1.023	1.069	1.100	N.D.
Economizer	0.930	1.006	1.057	N.D.
Sootblowers On (% of time)	19%	27%	31%	N.D.
Econ. Inlet Gas Temp (°F/°C)	668/353	697/369	716/380	N.D.
Heat Loss (percent)				
Dry Gas	6.19	6.16	6.14	5.26
Moisture from Fuel	1.44	1.45	1.46	1.20
Moisture from Combustion	5.21	5.17	5.14	5.35
Combustibles in Refuse	0.30	0.37	0.42	0.54
Radiation	0.39	0.36	0.34	0.33
Unmeasured	1.50	1.50	1.50	1.50
ASME Heat Loss Efficiency (%)	84.98	84.99	85.00	85.82
Net Heat Rate (Btu/kWh)	10,658	10,571	10,512	10,338
(kJ/kWh)	11,244	11,152	11,090	10,907

N.D. - Not determined

* 75 MWe

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SO_x-NO_x-Rox Box™ DEMONSTRATION PROJECT REVIEW

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ABSTRACT

The SO_x-NO_x-Rox Box™ (SNRB™) process is a combined SO_x, NO_x and particulate (Rox) emission control technology developed by Babcock & Wilcox in which high removal efficiencies for all three pollutants are achieved in a high-temperature baghouse. A 5-MWe equivalent demonstration of the technology cosponsored by the U.S. Department of Energy, the Ohio Department of Development/Ohio Coal Development Office and the Electric Power Research Institute has recently been completed at the Ohio Edison R.E. Burger Plant.

SNRB incorporates dry sorbent injection for SO_x emission control, selective catalytic reduction (SCR) for reducing NO_x emissions, and a pulse-jet baghouse operating at 450 to 850 °F for controlling particulate emissions. The unique, high-temperature baghouse/catalyst configuration provides for integrated particulate capture, SO_x removal, and NO_x reduction as well as the potential for reducing emissions of selected air toxics. The simultaneous, multiple emission control performance of SNRB is summarized using operating data generated in over 2,000 hours of operation at the demonstration site.

INTRODUCTION

The SNRB™ emission control process is a combination of three technologies:

- Dry sorbent injection for SO₂ removal
- Selective Catalytic Reduction (SCR) for NO_x reduction
- High-temperature fabric filtration for particulate control

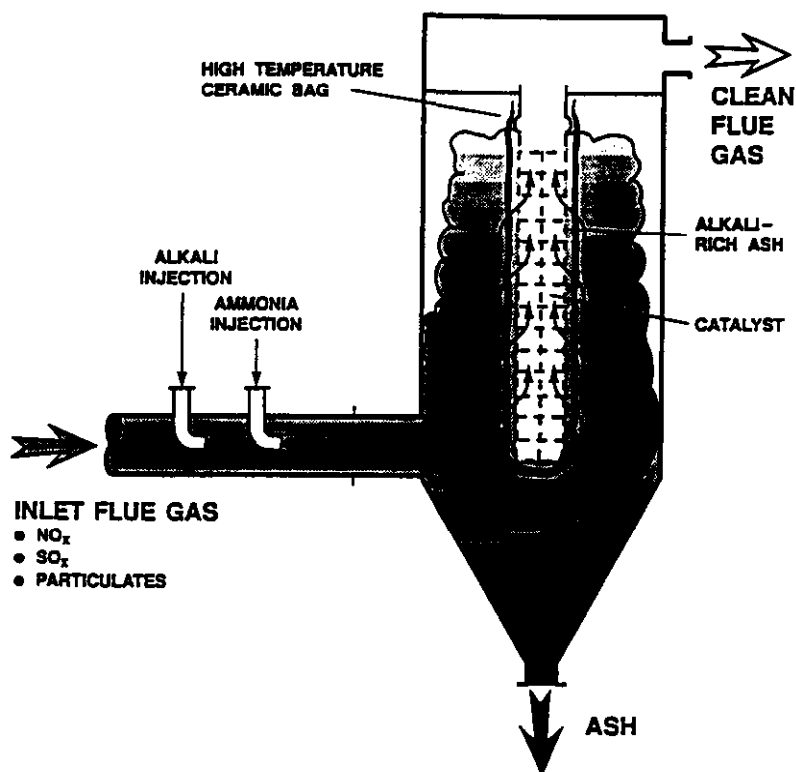
These technologies are combined as illustrated in Figure 1. The process is a post-combustion emission control technology which would be integrated into a power plant or industrial process between the combustion zone and the downstream heat recovery equipment.

The SNRB™ process includes several innovative characteristics which provide for a unique, high efficiency combined emissions control process. Operation of a pulse-jet baghouse at high temperatures requires that the filter bags be made of a fabric which can withstand exposure to flue gas at 800 to 900 °F while maintaining high particulate collection efficiency and flexibility. Integration of the SCR catalyst to minimize unreacted ammonia emissions and permit bag cleaning using conventional pulse-jet technology required development of a circular monolith catalyst. The unique features of the process provide several distinct advantages in comparison with competing emissions control technologies. These general advantages include:

- Multiple emissions control in a single component
- Low plan area space requirements
- Operating simplicity
- Flexibility for optimal overall control economics
- Enhanced SCR operating conditions
- Improved SO₂ sorbent utilization
- Dry materials handling

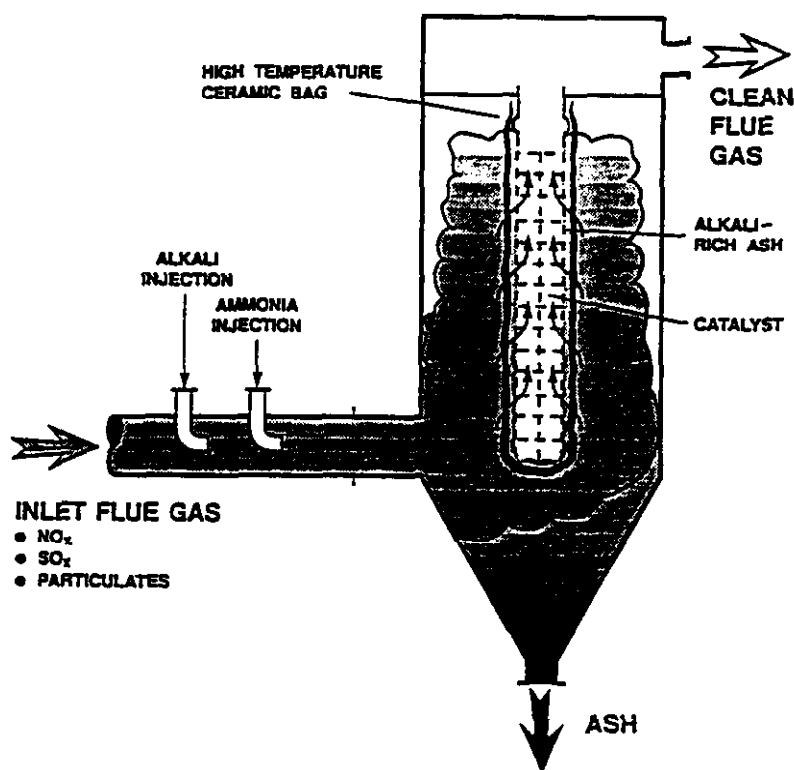
In certain applications, the initial SNRB™ system capital costs are lower than a combination of conventional systems for comparable emissions control.

Figure 1 - SNRB™ Process Schematic



Development of the SNRB™ process at Babcock & Wilcox began with pilot testing of high-temperature dry sorbent injection for SO_2 removal in the 1960's. Integration of NO_x reduction was evaluated in the 1970's. Pilot work in the 1980's focused on evaluation of various NO_x reduction catalysts, SO_2 sorbents and integration of the catalyst with the baghouse. This early development work led to the issuance of two US Process patents to Babcock & Wilcox - # 4,309,386 and # 4,793,981. An additional patent application for improvements to the process is pending. The Ohio Coal Development Office (OCDO) has been instrumental in working with B&W to develop the process to the point where a larger scale demonstration of the technology was feasible.

Figure 1 - SNRB™ Process Schematic



Development of the SNRB™ process at Babcock & Wilcox began with pilot testing of high-temperature dry sorbent injection for SO_2 removal in the 1960's. Integration of NO_x reduction was evaluated in the 1970's. Pilot work in the 1980's focused on evaluation of various NO_x reduction catalysts, SO_2 sorbents and integration of the catalyst with the baghouse. This early development work led to the issuance of two US Process patents to Babcock & Wilcox - # 4,309,386 and # 4,793,981. An additional patent application for improvements to the process is pending. The Ohio Coal Development Office (OCDO) has been instrumental in working with B&W to develop the process to the point where a larger scale demonstration of the technology was feasible.

SNRB™ FLUE GAS CLEAN-UP DEMONSTRATION PROJECT

The Clean Coal Technology Program demonstration is a key component in the SNRB™ technology commercialization effort. The demonstration provided for optimization of the catalyst integration arrangement, evaluation of operating conditions for maximizing simultaneous emissions control, investigation of alternative bag fabrics and evaluation of SO₂ sorbents for enhancing SO₂ removal. The project also permitted an assessment of the bag and catalyst suppliers ability to produce these key components to commercial specifications.

The SNRB™ Flue Gas Clean-Up Demonstration Project was selected for funding in the second round of the Clean Coal Technology Program. The \$13.3 million project was co-sponsored by the US Department of Energy, the Ohio Coal Development Office, Babcock & Wilcox, the Electric Power Research Institute and Ohio Edison. In-kind contributions were provided by 3M, Norton Chemical Process Products and Owens-Corning Fiberglas. DOE provided 45.8% of the total project funding. The Cooperative Agreement with DOE was signed in December, 1989 and completion of the project is scheduled for December, 1993.

The project scope was comprised of four primary test programs:

- Base demonstration project
- Filter fabric assessment
- Alternative bag demonstration
- Air toxics emissions testing

The overall project objectives included demonstration of greater than 70% SO₂ removal and 90% or higher reduction of NO_x emissions while maintaining particulate emissions below 0.03 lb/10⁶ Btu. A 5-MWe slipstream demonstration of the technology was the focus of the project. The demonstration incorporated commercial scale bag/catalyst assemblies.

Base demonstration project

The base SNRB™ project focused on the engineering, design and construction of a facility for evaluation of the emission control performance and operability of key components of the technology. The SNRB™ demonstration facility was constructed at the R.E. Burger Plant of Ohio Edison. The plant is located on the Ohio River south of Shadyside, Ohio.

Detailed design activity included pilot testing to finalize details of the filter bag and catalyst configurations and to screen operating conditions for the larger facility. Both pellet and honeycomb or monolith catalysts were evaluated in the design stage. The need for a cylindrical monolith catalyst to minimize the potential for emission

of unreacted ammonia was identified and provisions were made by Norton Chemical Process Products to extrude cylindrical catalyst sections for the demonstration.

Construction of the facility was completed in November, 1992. A five month start-up and shakedown period followed. The test program was initiated in May, 1992 and completed in April, 1993.

Filter fabric assessment program

A pilot baghouse was installed at a coal-fired utility to provide extended exposure testing for high-temperature filter bag fabrics. Three alternative fabrics were evaluated in a 1,300 ACFM slipstream pilot installed on Boiler #7 of the City of Colorado Springs Utilities Martin Drake Plant [1]. The baghouse was operated at 600 to 720 °F for a total of 3,700 hours over a 12 month period. Each bag experienced approximately 11,200 cleaning pulses.

Filter bags made of Nextel ceramic fibers, S2-Glass fiberglass fibers and Silontex were evaluated. The Nextel and S2-Glass fabrics demonstrated acceptable cleaning and strength characteristics. The Nextel bags were selected as the base filter bag for the 5 MWe demonstration.

Alternative bag demonstration

To continue evaluation of the S2-Glass filter bags, which are potentially a lower cost alternative to the Nextel bags, one module of the SNRB™ demonstration baghouse was equipped with these fiberglass bags. The bags were exposed to integrated SNRB™ operating conditions for a total of 1,490 hours. The S2-Glass filter bags held up well at operating temperatures of 800 to 900 °F through numerous start-ups and exposure to uncontrolled SO₂ and HCl emissions.

Air toxics emissions testing

A comprehensive air toxics emissions characterization test program was performed in which emissions at the inlet and outlet of the SNRB™ baghouse were compared to emissions from the host boiler and the Burger plant ESP. A detailed discussion of the test program has been provided by Czuczwa [2]. Emissions of targeted air toxics were measured over a six day period in April and May, 1993. The emissions monitored included trace metals, VOCs, semi-volatile organics, aldehydes, halides and radionuclide species. The test results have not yet been released for publication by the sponsors.

R.E. BURGER PLANT DEMONSTRATION

The components of the 5-MWe SNRB™ demonstration facility are summarized in Table 1. Key design characteristics of the major components are summarized in Table 2.

Table 1 - SNRB™ Demonstration Facility

- Six compartment pulse-jet baghouse
- Commercial scale bag/catalyst assemblies
- Independent injection/baghouse operation temperature control
- Pneumatic materials handling
- Dry sorbent storage and injection
- Anhydrous ammonia storage and injection

Table 2 - Design Specifications of Key Components

Pulse-jet baghouse

Flue gas flow	30,000 ACFM @ 800 °F
Air-to-cloth ratio	4:1
Operating temperature	450-900 °F
Filter bags	20' long x 6" diameter
Number of filter bags	252 (6 x 42)
Bag material	
3M	Nextel ceramic fibers
Owens Corning Fiberglas	S2-Glass fiberglass
Cleaning air pressure	30-40 psig
Cleaning air pulse	80-100 milliseconds
Catalyst	
Norton	NC-300 series zeolite

Sorbent handling

Storage	2,350 ft ³
Hydrated lime	300 to 700 lb/hr
Sodium bicarbonate	300 to 1300 lb/hr

Ammonia injection

Storage	1000 gallons
Dilution	19:1
Flow rate	3 to 30 lb/hr

The SNRB™ process treated a slip stream of flue gas from the Burger Plant boiler #8. The gas tie-in was between the economizer and the combustion air heater where the flue gas temperature was approximately 600 to 650 °F. This nominal 160-MWe, pulverized coal, wall fired B&W boiler has been in operation since 1955. Ohio Edison fired a blend of bituminous coals in the boiler with an average sulfur content of 3 to

4%. At the SNRB™ process inlet, the flue gas contained 2000 to 3000 ppm SO₂, 350 to 500 ppm NO_x and 3 to 4 grains/scf particulates.

The SNRB™ demonstration facility was operated for approximately 2,300 hours with sorbent and ammonia injection for emissions control. The facility experienced more than 25 cold start-up cycles. Despite these numerous start-ups, no degradation of the catalyst or filter bags was observed. The initial performance goals were exceeded. It is particularly worth noting that significantly higher SO₂ removal was obtained by optimizing the sorbent injection and baghouse operating temperatures and through the use of modified lime hydrates. In three periods of continuous operation for over 200 hours each, system availability averaged 99%.

SNRB™ DEMONSTRATION PERFORMANCE HIGHLIGHTS

The emission control performance observed at the SNRB™ demonstration over a range of operating conditions has previously been reported in detail [1,3,4]. This discussion will focus on a brief review of key operating results.

Table 3 summarizes performance with commercial grade hydrated lime injection and operation of the baghouse at 855 °F. This data reflects the average of several tests conducted at similar operating conditions at various times throughout the demonstration program.

Table 3 - SNRB™ Emission Control Performance

	Emissions (lb/10 ⁶ Btu)	
	Boiler Outlet	SNRB™ Baghouse
SO ₂	4.313	0.544
NO _x	0.660	0.067
Particulate	5.660	0.018

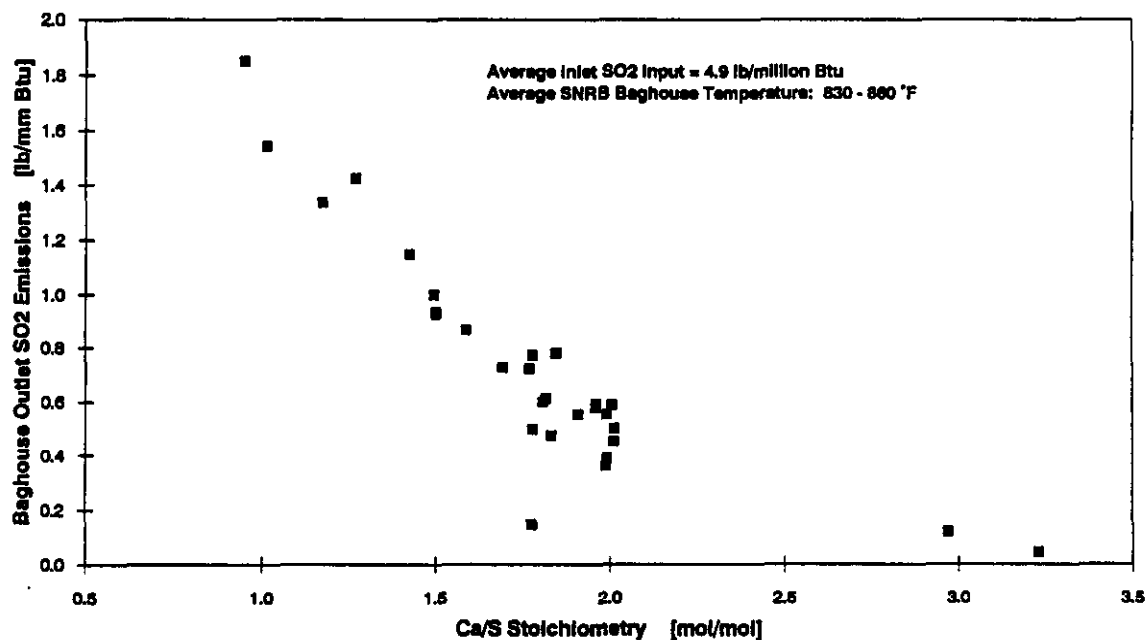
SNRB™ Operation	
Ca/S	1.95:1
NH ₃ /NO _x	0.84:1

SO₂ Emission Control

SO₂ emission control at the demonstration was optimized through evaluation of the sorbent injection and baghouse operating temperatures, operation over a range of Ca/S stoichiometric ratios and investigation of alternative SO₂ sorbents. A. R. Holmes has discussed the effects of each of these primary factors on SO₂ removal in detail [3].

As shown in Figure 2, with the baghouse operating above 830 °F, outlet SO₂ emissions were reduced to less than 1.2 lb/10⁶ Btu using Ca/S ratios of 1.4 and above.

Figure 2 - Effect of Ca/S Ratio on SO₂ Emissions

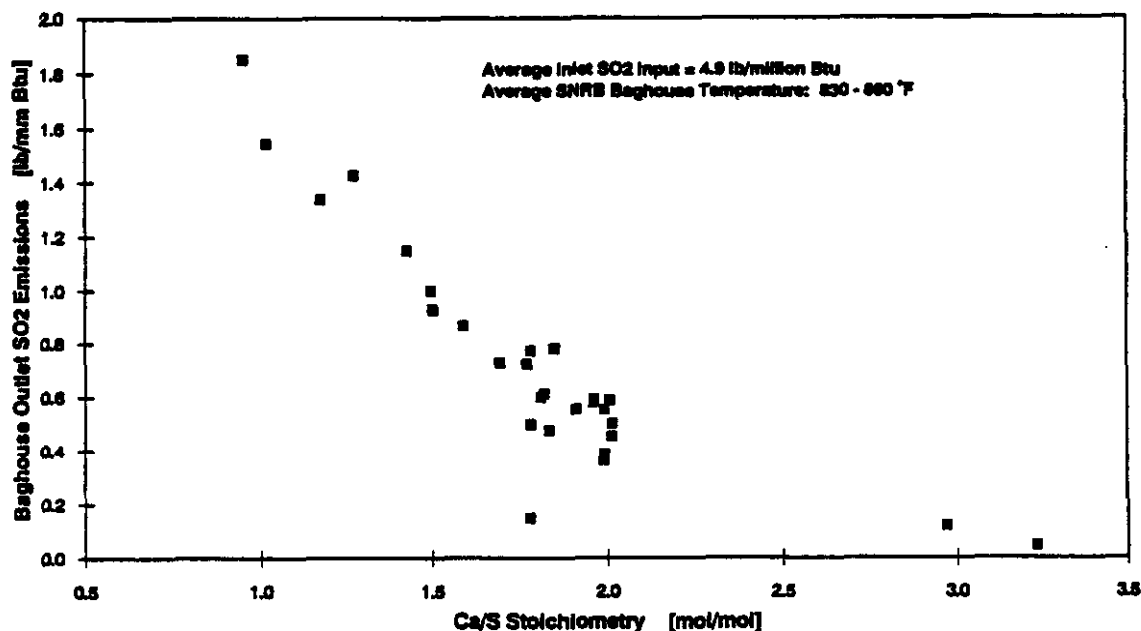


A commercial grade hydrated lime supplied by Dravo Lime Company was used for most of the operation of the SNRB™ demonstration. Approximately 225 tons of hydrated lime were used in the demonstration test program. Dravo also supplied approximately 90 tons of two alternative limes with the potential to improve SO₂ removal. Slight modifications were made to the operation of a commercial hydrator to produce finer mass mean diameter products through the addition of lignosulfonate or a sugar solution the hydrator [5]. At a Ca/S ratio of 2, both alternative hydrates yielded approximately an 8% improvement in performance over the base sorbent, pushing SO₂ removal over 90%.

The use of sodium bicarbonate, NaHCO₃, as the SO₂ sorbent provides for SO₂ emission control at a lower temperature. The observed performance with sodium bicarbonate injection for SO₂ control is summarized in Table 4. The system inlet SO₂ concentration ranged from 4 to 5 lb/10⁶ Btu.

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Table 4 - SO₂ Removal with Sodium Bicarbonate

		% SO ₂ Removal	SO ₂ Emissions lb/10 ⁶ Btu
Baghouse Operation @ 450 - 460 °F			
Na ₂ /S	1.0	84	0.78
	2.0	98	0.08
Baghouse Operation @ 600 - 625 °F			
Na ₂ /S	1.0	74	1.01
	2.0	92	0.40

Sorbent grade-extra fine sodium bicarbonate was supplied by Church & Dwight for these tests. The bicarbonate was 98% less than 200 mesh with a surface area of 4.5 m²/gram. A 95% NaHCO₃ purity was measured. In general, the use of NaHCO₃ results in a higher sorbent utilization than possible with hydrated lime.

The following key points characterize SNRB™ system SO₂ removal performance in the demonstration test program:

- Injection of the sorbent directly upstream of the baghouse at 825 to 900 °F resulted in higher overall SO₂ removal than injection further upstream at temperatures up to 1200 °F.
- With the baghouse operating above 830 °F, injection of a commercial hydrated lime sorbent injected at Ca/S ratios of 1.8 and above resulted in SO₂ removals over 80%.
- SO₂ removals of 85 to 90% were obtained with Ca utilizations of 40 to 45%. This is significantly higher than the 60% removal, 30% utilization typical of other dry Ca(OH)₂ injection processes.
- The use of NaHCO₃ as the SO₂ sorbent permitted high removal efficiencies at significantly reduced baghouse operating temperatures.
- SO₂ emissions were reduced to less than 1.2 lb/10⁶ Btu with a 3 to 4% sulfur coal with Ca/S ratios as low as 1.5 and Na₂/S ratios less than 1.

NO_x Emission Reduction

The unpromoted, zeolite SCR catalyst installed at the demonstration was formulated for optimal performance at temperatures above 750 °F. In this temperature region, outlet NO_x emissions were reduced to less than 0.05 lb/10⁶ Btu with NH₃/NO_x ratios of 0.85 and above with the

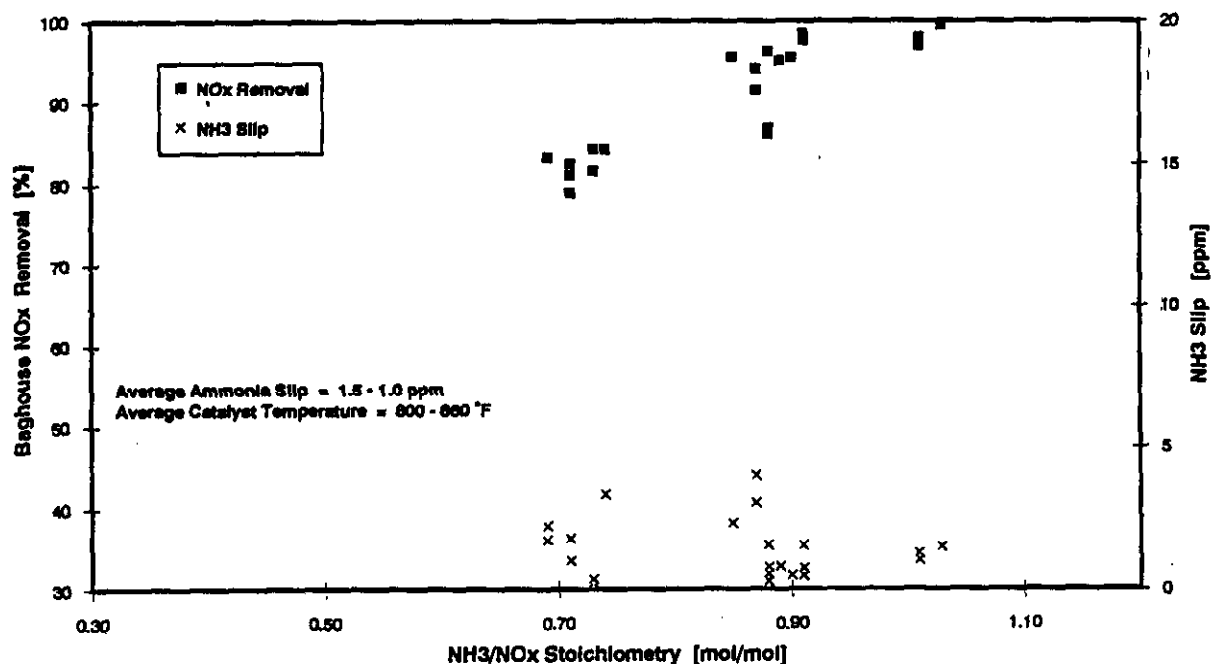
baghouse operating temperature above 800 °F. NO_x emission reduction for baghouse operating temperatures of 790 to 865 °F is summarized in Table 5.

Table 5 - Average NO_x Emissions at the Burger Plant Demonstration

NO _x Emissions lb/10 ⁶ Btu	
SNRB™ Inlet	0.54 to 0.72
SNRB™ Outlet	
NH ₃ /NO _x ratio	
0.5	0.30
0.7	0.14
0.9	0.03

The emission of unreacted ammonia downstream of an SCR unit is a primary concern with SCR system operation. Periodic ammonia slip measurements were obtained using a modified EPA Method 5 sample train over a range of operating conditions. Figure 3 presents NO_x removal and ammonia slip data obtained by a third party testing contractor.

Figure 3 - NO_x Removal and Ammonia Slip



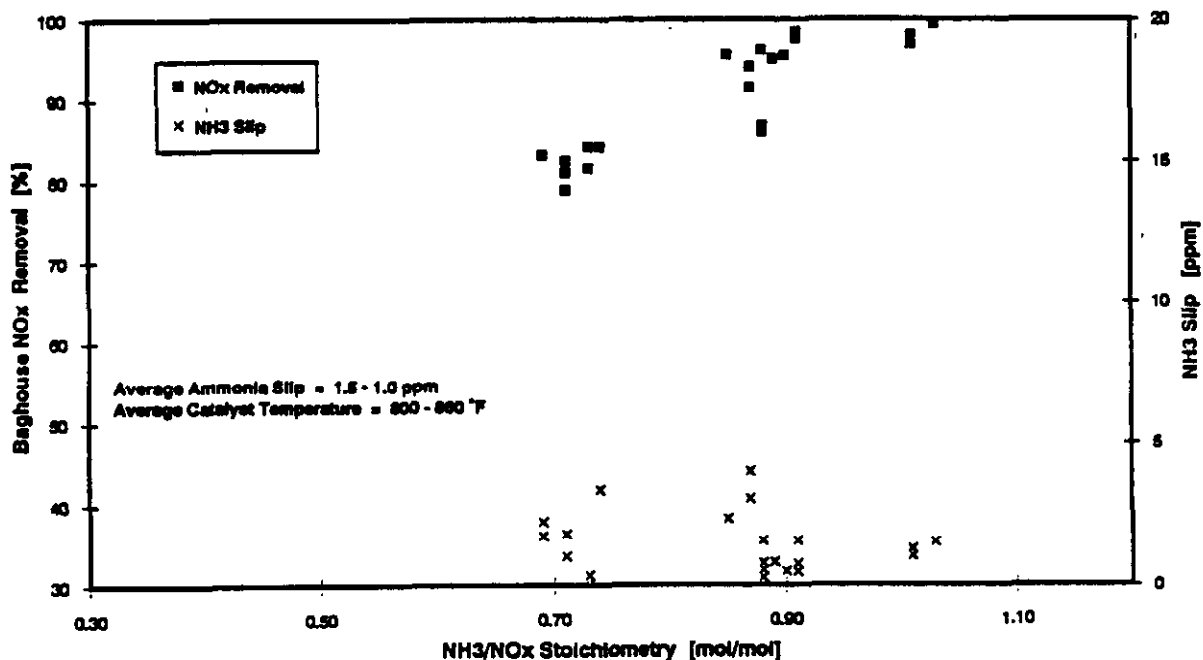
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Ammonia slip levels below 5 ppm are well within the limits typically found for commercial SCR installations. Short term operation of a continuous NH_3 analyzer confirmed the low ammonia slip measured with the flue gas sampling trains.

Key SNRBTM NO_x reduction observations from the demonstration tests may be summarized as follows:

- 90% NO_x emission reduction was readily achieved with ammonia slip limited to less than 5 ppm. This performance reduced NO_x emissions to less than 0.10 lb/10⁶ Btu.
- NO_x reduction was insensitive to temperature over the catalyst design temperature range of 700 to 900 °F.
- Catalyst space velocity (volumetric gas flow/catalyst volume) had a minimal effect on NO_x removal over the range evaluated.
- Turndown capability for tailoring the degree of NO_x reduction by varying the rate of ammonia injection was demonstrated for a range of 50 to 95% NO_x reduction.
- No appreciable physical degradation or change in catalyst activity was observed over the duration of the test program.
- The degree of oxidation of SO_2 to SO_3 over the zeolite catalyst appeared to be less than 0.5%. SO_2 oxidation is a concern for SCR catalysts containing vanadia to promote the NO_x reduction reaction.
- TCLP analysis of the catalyst after completion of the field tests confirmed that metal concentrations were well below regulatory limits and the catalyst remained non-hazardous for disposal.

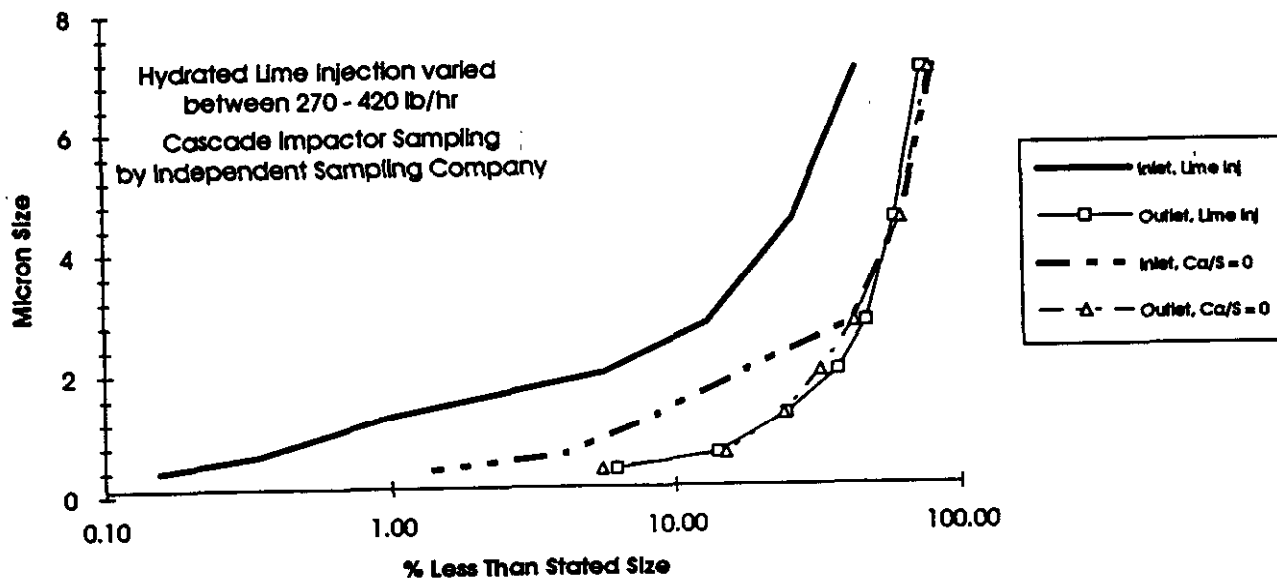
Particulate Emissions

EPA Method 5 sampling downstream of the baghouse confirmed that particulate emissions were consistently below the NSPS standard of 0.03 lb/10⁶ Btu. Variations in particulate emissions could not be correlated with the hydrated lime injection rate, air-to-cloth ratio, baghouse pressure drop, bag cleaning frequency or combination of modules in service. The average of over 30 baghouse particulate emission measurements was 0.018 lb/10⁶ Btu. A detailed discussion of particulate emission control at the demonstration has been provided by Evans, et al [1].

The results of cascade impactor sampling of the baghouse inlet and outlet flue gas streams are shown in Figure 4. The comparison clearly

shows the increased fineness of the solids at the baghouse inlet when hydrated lime is injected at 270 to 420 lb/hour. The size distribution of the baghouse emissions was consistent with and without lime injection.

Figure 4 - Average Particle Size Distributions



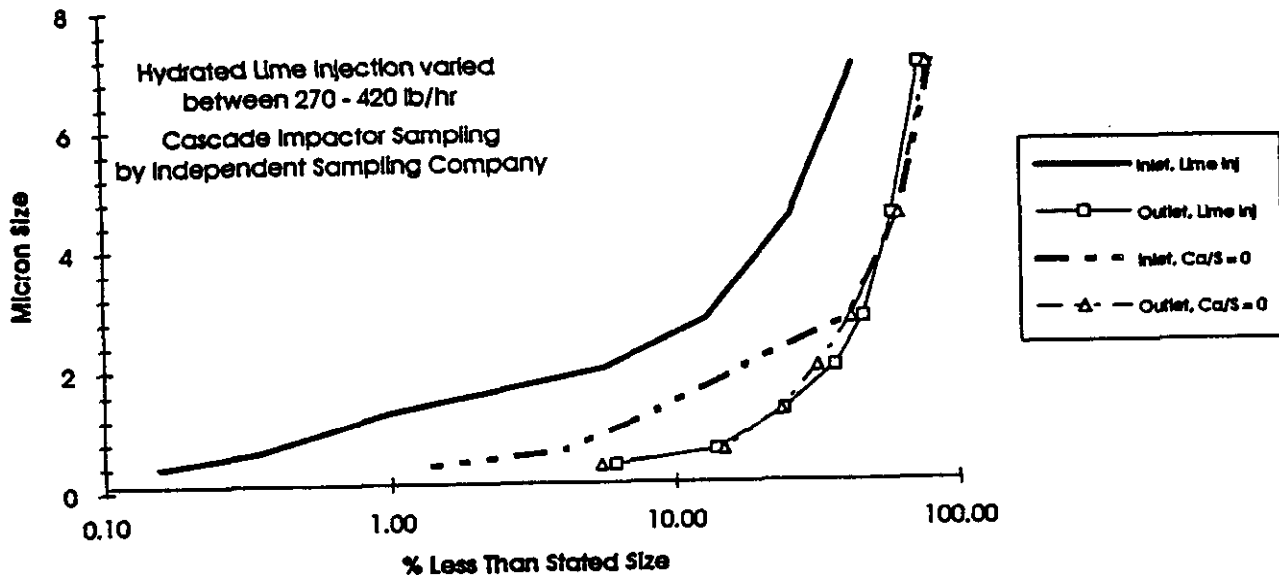
Additional particle size distribution measurements of the baghouse outlet emissions using cyclone collectors revealed that on average about 80% of the emissions were less than 10 microns and 40% were less than 1 micron.

A summary of key observations related to particulate collection at the SNRB™ follows.

- Hydrated lime injection increased the baghouse inlet particulate loading from an average of 5.6 to 16.5 lb/10⁶ Btu (3.2 to 9.3 grains/SCF).
- Emission testing with and without the SCR catalyst installed revealed no apparent difference in collection efficiency.
- On-line cleaning with a pulse air pressure of 30 to 40 psi was sufficient for cleaning the bag/catalyst assemblies.
- Typically, one of the five baghouse modules in service was cleaned every 30 to 150 minutes.

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Byproduct Characterization

Operation of the demonstration generated a total of approximately 830 tons of fly ash and byproduct solids. Approximately 30 tons of this material was used for evaluation of potential applications. The remaining solids were disposed of in a solid waste landfill.

Table 6 provides a typical composition of the baghouse solids with injection of commercial hydrated lime at a Ca/S ratio of 2. The coal contained approximately 3.5% sulfur and 12% ash.

Table 6 - SNRB™ Solids Composition

Constituent	Weight % of Total
Fly ash	32.8
CaCO ₃	23.9
CaSO ₄	20.5
CaSO ₃	15.4
CaO	7.4

The key characteristics of the solids collected in the SNRB™ baghouse are as follows:

- The moisture content of the baghouse product was typically below 0.5% and the product showed little affinity for picking up moisture even after outdoor storage for several months.
- Leach potential (TCLP) well below regulatory limits for solid waste disposal.
- No ammonia was detected in the baghouse solids.
- The pH of the solids ranged from 10.5 for sodium bicarbonate injection to 12.4 for hydrated lime injection.

A variety of potential uses for the solids have been investigated. Spreadability tests for soil amendment applications were performed with several types of agricultural lime spreaders. These tests indicated the low bulk density and moisture content of the material may require an intermediate pelletizing step for efficient application of the material for agricultural liming. The SNRB™ solids were found to have a pozzolanic activity index above the minimum required for fly ash to be used in concrete. The final compressive strength of the mortar using SNRB™ solids was comparable to that of the base mortar indicating the solids could be used as a partial cement replacement to lower the cost of the concrete. Further evaluations of potential applications for the byproduct solids are planned.

Corrosion Study

A concern for application of SCR to coal fired boilers is the oxidation of SO_2 to SO_3 . Subcontractor testing indicated the SNRB SCR configuration results in minimal, if any, net oxidation of SO_2 to SO_3 . To some extent, the SO_3 content of the flue gas determines the minimum exit temperature at which the combustion air heater can be operated to minimize corrosion of the heat transfer surfaces. This minimum exit temperature influences the net thermal efficiency of the power plant.

An air-cooled deposition probe was installed downstream of the outlet flue gas cooler to expose coupons of carbon steel (A36) and Corten (A588) to a flue gas temperature range of 150 to 260 °F. The probe was exposed for approximately 300 hours of operation with $\text{Ca}(\text{OH})_2$ injection upstream of the baghouse resulting in an average SO_2 emission rate of 1.13 lb/10⁶ Btu. The concentration of SO_3 in the flue gas downstream of the baghouse was on the order of 5 to 10 ppm. Analysis of the corrosion rate as a function of probe temperature indicated that operation below approximately 250 °F resulted in an unacceptable level of corrosion. Additional, longer term testing is needed to further assess the impact of reduced operating temperature on heat recovery equipment performance downstream of a SNRB™ emission control system.

PROJECTED COMMERCIAL SNRB™ ECONOMICS

A preliminary cost model has been used to evaluate the projected capital costs of a SNRB™ system for various utility boiler emission control applications. For a 250-MWe boiler fired with 3.5% sulfur coal and generating 1.2 lbs NO_x /10⁶ Btu, the projected capital cost of a SNRB™ system is approximately \$260/kw which includes various technology and project contingency factors. A combination of a fabric filter, SCR and a wet scrubber for achieving comparable emissions control has been estimated at \$360 to \$400/kw [3]. A comparison of the SNRB™ system with a combination of SCR, dry scrubbing for SO_2 control and a baghouse has indicated SNRB™ system capital costs are competitive with this combination for smaller units burning lower sulfur coal [6]. The capital cost of the SNRB™ system was projected to be 20% less than a SCR/dry scrubber/baghouse combination for a 100-MWe plant burning 1.5% sulfur coal. The levelized costs expressed as \$/ton of SO_2 and NO_x removed were also lower for SNRB™.

Variable operating costs are dominated by the cost of the SO_2 sorbent for a system designed for 85 to 90% SO_2 removal. Fixed operating costs primarily consist of system operating labor and projected labor and materials for the hot baghouse and ash handling systems.

COMMERCIALIZATION

Relatively few long term Clean Air Act compliance decisions such as installing wet scrubbers have been made by utilities for Phase 1 compliance. Fuel switching provides utilities with time to evaluate the allowance trading market and consider emerging clean coal technologies such as SNRB™ as a future compliance option [7]. SNRB™ can compliment a near term fuel switching strategy for SO₂ emission compliance by adding the flexibility of variable sorbent injection rates to enhance existing emissions reduction and providing a greater degree of fuel supply flexibility while integrating NO_x emission control and upgrading particulate emission control capability.

B&W is actively exploring potential power generation and industrial coal-fired boiler applications. Activity to date has been focused on smaller units where the cost advantages appear to be greatest. Potential applications to waste-to-energy plant emission control are also being investigated.

For smaller, low-capacity-factor units, the SNRB™ system provides quick on/off sorbent injection flexibility for short term operation with variable coal sulfur contents. The sorbent injection system represents a relatively minor component, projected to be less than 15%, of the total system capital cost. Integration of the SNRB™ system with fuel switching strategies or low NO_x combustion modifications provides a high overall level of emissions reduction with reduced capital and operating costs.

Commercialization efforts will benefit from successful installations of pulse-jet fabric filters for controlling particulates and selective catalytic reduction for NO_x emission control in a variety of industrial and utility applications. High-temperature filtration is gaining interest for integrated, combined cycle system designs.

In 1996, the first US pulverized coal fired utility equipped with SCR for controlling NO_x emissions will begin operations [7]. The 440 MW Stanton Unit 2 is owned by the Orlando Utilities Commission. The NO_x control portion of the SNRB™ system capital and operating costs should follow the costs of more conventional SCR systems which have shown a dramatic decline in recent years.

The retrofit market is influenced by several factors including local NO_x emission regulations, performance of existing particulate control equipment, boiler age and planned service life and potential air toxics emission regulations.

SUMMARY

The SNRB™ system provides for high efficiency control of the primary emissions from coal-fired boilers. The system is capable of exceeding the SO₂ emission control performance of existing dry sorbent injection technologies. NO_x emission reduction comparable to commercial, conventional SCR systems has been demonstrated. In fact, emissions control at the SNRB™ demonstration exceeded the initial project goals. Additional work scope funded by the project cosponsors addressed several key questions for commercialization of the technology such as expected filter bag life and air toxics control potential. Commercial-scale components used in the demonstration performed well and the component manufacturers demonstrated the ability to produce the components to commercial specifications. In all of the extended periods of continuous operation, the process achieved a high level of reliability and the operability of the subsystems was clearly demonstrated.

B&W is pursuing commercial application of the technology, using the successful 5-MWe demonstration as proof of the technical feasibility of the process and evaluating the unique requirements of specific new and retrofit applications as opportunities are identified.

ACKNOWLEDGEMENTS

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PERFORMANCE RESULTS FROM THE 35 MW SNOX DEMONSTRATION AT OHIO EDISON'S NILES STATION

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ABSTRACT

The SNOX Process is a highly efficient catalytic process that removes SO_2 and NO_x from flue gas and generates salable sulfuric acid. The integrated design of the process enables high removal efficiencies, no waste production, and increased thermal efficiency of the boiler. As part of the Clean Coal Technology Program, this process is being demonstrated under joint sponsorship from the U.S. Department of Energy, Ohio Coal Development Office, ABB Environmental Systems, Snamprogetti, and Ohio Edison.

The project objective is to demonstrate the SO_2 and NO_x reduction efficiencies of the SNOX process on a U.S. electric power plant firing high-sulfur Ohio coal. This 35-MWe demonstration is being conducted by retrofitting a 108-MWe existing power plant -- Ohio Edison Niles Station boiler No. 2 -- in Trumbull County, Ohio.

Initial performance results indicate efficiencies in excess of the goals of 90% NO_x removal and 95% SO_2 removal. Sulfuric acid concentration has also met the design goal of >93 wt. %, and color and clarity meet expectations. Information from approximately one year of the twenty-two month test program is presented in this paper.

INTRODUCTION

The SNOX Demonstration Project is a flue gas treatment facility designed to treat one-third of the flue gas from the 108 MWe Ohio Edison Niles Power Station Unit No.2 boiler. The process utilizes selective catalytic reduction (SCR) for NO_x control and a unique sulfuric acid recovery process for SO₂ removal. More than 95 % of the sulfur dioxide and 90% of the nitrogen oxides are expected to be removed while producing high purity sulfuric acid as the only by product. The SNOX Process was developed in Denmark by Haldor Topsøe A/S and is offered under license in North America by ABB Environmental Systems.

The Department of Energy (DOE) is funding 50% of this \$31.4 million demonstration project in Niles, Ohio under the Clean Coal Technology II program. Co-sponsors of the project include the Ohio Coal Development Office, Ohio Edison Company, Asea Brown Boveri Environmental Systems (ABBES) and Snamprogetti USA Inc.

The Cooperative agreement between DOE and ABB was signed on December 20, 1989, officially initiating the start of the demonstration project. Engineering and design began on January 2, 1990, and was part of a twenty-five month design/construction period. Site construction activities began in the fall of 1990. Initial operation started in March 1992 and testing is scheduled to continue until the end of 1993.

Although this is the first application in the United States to demonstrate this process, commercial scale plants are operating successfully in Denmark and Sicily. Denmark has the largest SNOX operation which was successfully retrofitted to a 300 MW coal fired boiler in Vodskov, Denmark. The power station is owned by NEFO, the North Jutland Electricity Supply Company, and burns a blend of 2.8% sulfur coal, part of which is imported from Ohio. The NEFO plant started operations in October 1991 and is currently operating at full load with impressive removal efficiencies of 95 % for SO₂ and NO_x. The 30,000 tons of commercial grade acid produced per year from the NEFO SNOX plant are sold to the fertilizer industry.

A primary objective of the Niles demonstration project is to determine the competitiveness of

this process from both capital and operating cost bases as compared with other technologies employed in the United States.

SNOX PROCESS DESCRIPTION

The SNOX technology consists of five (5) key process areas: particulate collection, nitrogen oxides (NO_x) reduction, sulfur dioxide (SO_2) oxidation, sulfuric acid (H_2SO_4) condensation and sulfuric acid management. Heat transfer and recovery also represent a significant part of the SNOX system. The integration of these individual steps is shown in Figure 1, which is the process flow diagram for the system installed on the Niles Unit 2 boiler.

Referring to Figure 1, a slip stream from the Unit 2 boiler is taken upstream of the existing electrostatic precipitator and heated to approximately 400°F by an in-line natural gas fired burner before entering a fabric filter for particulate collection. The flue gas is heated to simulate the inlet temperature to a SNOX system for a full size installation. After passing through a booster fan, the flue gas is heated to above 700°F through the primary side of a gas/gas heat exchanger (GGH).

An ammonia and air mixture is then added to the gas prior to the selective catalytic reactor (SCR) where nitrogen oxides are reduced to free nitrogen and water. The flue gas leaves the SCR, its temperature is raised slightly by an in-line burner, and enters the SO_2 Converter which oxidizes SO_2 to sulfur trioxide (SO_3). The SO_3 laden gas is passed through the secondary side of the GGH where it is cooled as the incoming flue gas is heated.

The processed flue gas is then passed through a falling film condenser (the WSA Condenser) where it is further cooled with ambient air to below the sulfuric acid dewpoint. Acid condenses out of the gas phase on the interior of borosilicate glass tubes and is subsequently collected, cooled and stored. The flue gas is discharged from the process at about 210°F and cooling air leaves the WSA Condenser at approximately 400°F. In a full size, integrated system the hot air is used for process support and as boiler combustion air after collecting more heat through the air preheater. For the SNOX demonstration at the Niles facility, the WSA Condenser

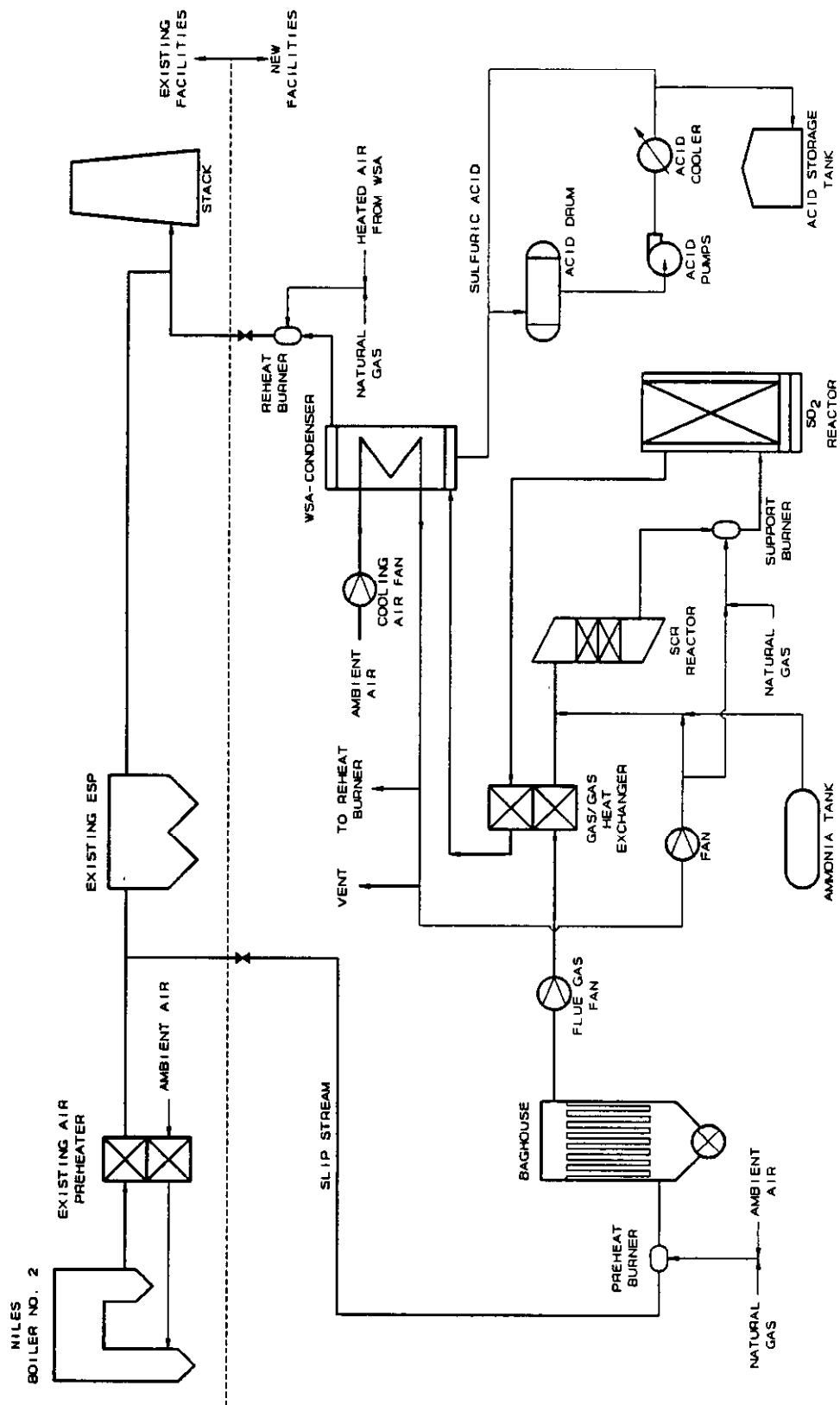


Figure 1
Niles Station Process Flow Diagram

cooling air is vented and not returned to the boiler air preheater because the entire boiler flue gas output is not being treated.

The hot, concentrated sulfuric acid product at about 400°F is collected and circulated through a thermoplastic lined system consisting of a holding tank, circulation pumps, and a water-cooled shell and tube heat exchanger. The purpose of this loop is to cool the acid to more conveniently manageable temperatures (70-100°F). Acid from the recirculation loop is then pumped to the main acid storage tank.

TEST PROGRAM AND STATUS

In order to demonstrate and evaluate the performance of the SNOX process during the Clean Coal Technology Program, general operating data is being collected and parametric tests conducted to characterize the process and equipment. An outline of the plan is presented below along with a description of the status of the parametric testing program. The primary objectives for the SNOX Demonstration Project are as follows:

1. Demonstrate NO_x and SO₂ removals of 90 and 95 %, respectively.
2. Demonstrate the commercial quality of the product sulfuric acid.
3. Satisfy all Environmental Monitoring Plan requirements.
4. Perform a technical and economic characterization of the technology.

The following secondary objectives are identified in order to fully establish a basis for the technical and economic evaluation of a commercial application of this technology.

1. Execute parametric test batteries on all major pieces of equipment.
 - Fabric Filter
 - SCR System
 - SO₂ Converter
 - WSA Condenser
 - Gas/Gas Heat Exchanger
 - Catalyst Screening Unit
2. Quantify process consumptions.
 - Power
 - Natural Gas
 - Catalysts
 - Cooling Water

- Potable Water
 - Ammonia
3. Quantify process productions.
 - Sulfuric Acid
 - Heat
 4. Quantify personnel requirements.
 5. Evaluate all materials of construction.

All information required to monitor the general health and environmental performance of the SNOX Plant is archived through the computerized Distributive Control System at six minute intervals into a magnetic media data base. The specific parameters include such items as temperatures, pressures, flows, gaseous concentrations, etc; and comprise 67 different data bits. Routine analyses of inputs and outputs of the process requiring manual sampling are also made and their results are fed into the Master Data Base. The following lists the parameters that are tested, the analytical methods used, and the frequency of each test.

<u>Stream</u>	<u>Parameter</u>	<u>Method</u>	<u>Frequency</u>
Coal	H ₂ O, Ash, S, Btu/lb	Proximate	Daily
	C, H, N, O	Ultimate	Monthly
	Trace Elements (1)	(2)	Quarterly
	Cl, F	(2)	Quarterly
Product Acid	wt. %	Titration	Each Load
	Color	APHA Standards	Each Load
	Fe	(2)	Each Load
	Trace Elements (1)	(2)	Monthly
	Cl, F	(2)	Monthly
	SO ₂ , NO ₃ , NH ₄	(2)	Monthly
Acid Dilution Water	Trace Elements (1)	(2)	Quarterly
	Cl, F	ISE (3) or IC (4)	Quarterly
	Alkalinity	Titration	Quarterly
	SO ₂ , NO ₃ , NH ₄	(2)	Quarterly
Ammonia	wt. %	(2)	Quarterly
	Oil	(2)	Quarterly

Flyash	Trace Elements (1)	(2)	Quarterly
Catalyst Siftings	Heavy Metals	EP Toxicity	Each Occurrence
	Heavy Metals	TCLP	Each Occurrence
	Trace Elements (1)	(2)	Each Occurrence

- (1) Trace Elements defined as As, B, Cd, Cr, Cu, Fe, Hg, K, Mg, Mn, Na, Ni, Pb, Se, V, Zn.
- (2) Best Available Method
- (3) Ion Specific Electrode Method
- (4) Ion Chromatography

To initiate the SNOX system parametric testing program, a group of tests were conducted on the Unit 2 boiler to characterize its gaseous and particulate emissions ahead of the existing electrostatic precipitator and also at the stack discharge. At both locations, tests have been conducted for:

- Flow, temperature, pressure;
- Particulate loading and size distribution;
- SO₂, SO₃, NO, NO₂, N₂O, O₂, CO₂, CO, H₂O, HCl, F, NH₃; and
- As, B, Cd, Cr, Cu, Fe, Hg, K, Mg, Mn, Na, Ni, Pb, Se, V, Zn.

Many tests for the SNOX system are designated to be conducted at three SNOX system loads - 75 %, 100%, and 110% of design capacity. At this time, the following major tests have been conducted, most at all three load conditions:

- System venturi calibration;
- Fabric filter characterization (in and out) for same items as Unit 2 testing;
- Gas/gas heat exchanger pressure drop, temperature profiles, overall performance;
- SCR inlet flow and temperature distribution, NO_x and NH₃ in and out;
- SO₂ converter catalyst beds temperature and flow distribution;
- WSA Condenser SO₂ and SO₃ outlet concentrations by compartment, as well as compartment flow, temperature, and O₂ concentration; and
- Simultaneous manual samples at the system inlet and outlet for SO₂ and NO_x.

Results from these tests as well as instrument data is currently being analyzed to assess system performance and make adjustments to system parameters and components. The cumulative SNOX plant operating time is shown in Figure 2, which in June 1992 totalled more than 5200 hours.

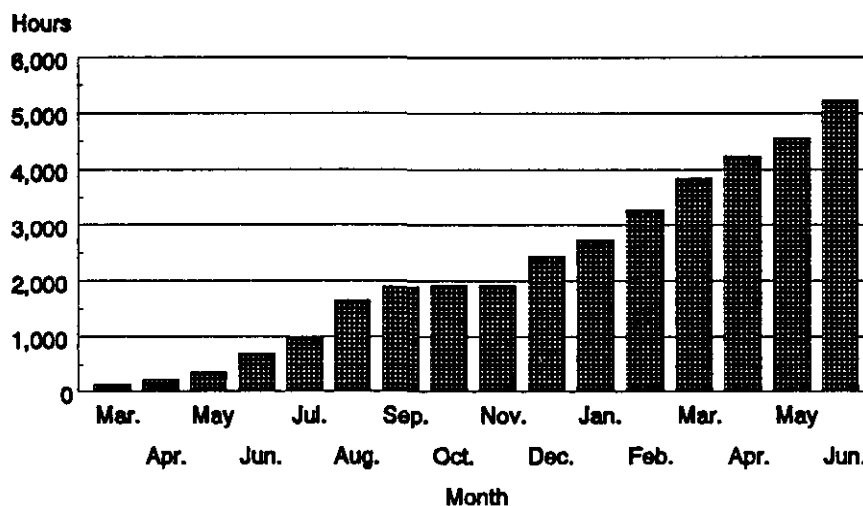


Figure 2
SNOX Plant Cumulative Operating Time

SYSTEM PERFORMANCE

Particulate Collection

The fabric filter employed at the SNOX Demonstration Plant is a six-module unit with pulsed air cleaning. Each module or compartment is approximately 13 feet x 10 feet and contains 266 bags, each 14 feet long by 6 inches in diameter. The filter bags are constructed of PTFE membrane on fiberglass backing and a total of 1596 bags are in the six compartments, resulting in a total area of 35,098 square feet. Net air to cloth ratio was designed for 4.55 acf/ft² but normally operates at about 4.4 acf/ft² at the "design" full load of the SNOX plant (78,000 scfm @ 60°F). Net air to cloth ratio is calculated based on five modules in service.

As will be described further in the SO₂ removal discussion, the SO₂ catalyst has a semi-molten surface at operating temperature and removes about 90% of the particulate which passes across it. For this reason, high efficiency particulate collection upstream of the SNOX process is an advantage in that it minimizes the frequency that this catalyst must be cleaned. Prior to operation it was estimated that the cleaning frequency with PTFE membrane bags would be

Table 1**Particulate Loadings at Baghouse Inlet and Outlet, and System Outlet**

Date	Baghouse Inlet		Baghouse Outlet		System Outlet	
	gr/ dscf	mg/ dNm ³	gr/ dscf	mg/ dNm ³	gr/ dscf	mg/ dNm ³
7/11/92	.7564	1858	.0047	11.5		
7/11/92	.5887	1446	.0133	32.7		
7/13/92	.6108	1500	.0087	21.4		
12/18/92	.6885	1691	.0056	13.7	.0033	8.10
12/18/92	.7886	1937				
12/20/92	.6915	1698	.0034	8.35	.0114	28.0
12/20/92	.9824	2413				
12/21/92	.7166	1760	.0230	56.5	.0032	7.86
12/21/92	.7534	1850				

about one year. It was also planned to purposely increase the particulate loading to higher values in order to determine its impact on ash build-up rate in the SO₂ catalyst. While high efficiency particulate collection is an advantage, it is not a necessity with the SNOX process and higher loadings only increase the catalyst cleaning frequency.

Particulate loadings have been sampled twice at this stage of the test program. The first set of samples were taken in July of 1992 and the second set in December of 1992. Results from these tests are listed in Table 1. At inlet loadings of .59 - .98 gr/dscf the outlet loadings were very variable. While three outlet loadings were grouped between .003 and .006 gr/dscf, the other three were significantly higher and ranged from .0087 to .023 gr/dscf. These outlet loadings were much higher than anticipated for PTFE membrane bags - closer to .0004 gr/dscf was expected. At the system outlet, three samples were taken during the December 1992 test runs. Two of the values were very close, .0032 and .0033 gr/dscf, while the third appears to be an anomaly. In this sample, as well as some of the higher bag filter outlets, large particles were present on the filter causing the high values.

Prior to the unit being started in March of 1992 a "black light" test had been conducted to identify any leaks in compartments or bags. Corrections had been made at that time to eliminate any leaks before the particulate tests were conducted. The high inlet loadings indicated that the condition of the fabric filter bags needed to be examined again. In subsequent filter bag examinations it was determined that the ash layer was significantly acidic, and that the bag material had lost much of its original strength. As a result, small pinholes were forming in some of the bags. A problem also existed with high pressure drop across the bags due to an uncleanable portion of deposit. It appears that this "sticky" layer of ash was the more acidic portion and was contributing to both the high pressure drop and bag deterioration.

As to the cause of the acidic ash, it appears that start up problems related to the natural gas fired, in-line burner upstream of the fabric filter contributed to periods of acid condensation occurring on the flyash before the fabric filter or in the fabric filter. The purpose of this in-line burner is to both prevent the flue gas temperature from dropping below the acid dewpoint and to raise the flue gas to a temperature ($\approx 400^{\circ}\text{F}$) which is typical of what would occur in a full size, integrated SNOX plant when the WSA Condenser cooling air is used as combustion air to the boiler air preheater (raising the temperature of the flue gas exiting the air preheater). Given the condition of the bags, it was decided to replace all of the them during June of 1993. Although particulate loadings leaving the baghouse have been higher than anticipated for much of the first 13 months of operation, valuable data has been obtained concerning operation of the SNOX plant at loadings which are more typical of electrostatic precipitator outlets. The impact of these higher loadings will be presented in the section discussing the SO_2 Converter.

NO_x Reduction

Nitrogen oxides are converted to nitrogen and water vapor in the SNOX Process via selective catalytic reduction with ammonia (NH_3). The catalyst and SCR reactor design used for this project were supplied by Haldor Topsøe A/S, the developer of the SNOX Process. This design is a top down gas flow arrangement with three (3) catalyst bed levels, two (2) of which are initially filled and one (1) is spare. The reactor casing is constructed of A-204 high temperature steel and sized for an effective design space velocity of about 7500 h^{-1} .

The DNX-932 catalyst used in this design is a high activity, titanium oxide based monolithic type which operates in the temperature range of 650-800°F. This low particulate loading version of the DNX line has a hydraulic diameter of 0.122 in. and a specific area of 235 ft²/ft³.

This project incorporates a unique form of ammonia evaporation and dilution prior to its injection across the SCR inlet duct. Liquid ammonia is atomized into a slipstream of hot (\approx 400°F) discharge cooling air from the WSA Condenser. Thus, the ammonia is evaporated and diluted in one step involving a relatively low cost valve/atomizer unit. Conventional systems employ an evaporator which has higher associated capital and operating costs.

The strategic location of the SCR reactor in the SNOX Process as compared to conventional high dust SCR applications results in several benefits. First, the post fabric filter, low dust environment allows the use of high specific area catalyst and thus lower catalyst volumes. In addition, much lower catalyst erosion can be expected as well as less potential for poisoning from gaseous arsenic. Both of these aspects significantly increase catalyst lifetime. Also as a result of the low dust stream, sootblowers are not necessary.

Second, the location of the SCR reactor upstream of the SO₂ Converter allows operation at an ammonia surplus of 1.02 to 1.05 without the potential of downstream ammonium sulfate and ammonium bisulfate condensation which is a usual result of excess ammonia slip. All ammonia slip in the SNOX Process is oxidized in the downstream oxidation reactor. Operation with this ammonia surplus greatly reduces the catalyst volume necessary for a given NO_x removal. The relative location of the two reactors has one other benefit. In conventional SCR applications, catalysts are required not to oxidize more than about one (1) percent of the inlet SO₂ to SO₃ in order not to increase the downstream sulfuric acid dewpoint significantly. This requirement often has a side effect of reduced catalyst NO_x removal activity and thus higher catalyst volumes. The SNOX Process does not have this limitation since any SO₂ oxidation in the SCR reactor only benefits the oxidation reactor downstream. Therefore, very high activity SCR catalyst is utilized.

A series of initial tests have been run to characterize the baseline performance of the SCR

system at the Niles facility. Inlet and outlet transverse were run for NO_x as well as outlet transverse for NH_3 . The tests were executed at 100% load and at various stoichiometric ratios (SRs) of NH_3 to NO_x . A SR of 1.0 resulted in 99.7% NO_x destruction across the SCR reactor. All SRs from 1.02 to 1.09 resulted in 99.9% removal. These performance results were obtained at inlet NO_x concentrations of 500 - 700 ppmv. Ammonia slip through this test series ranged from zero (0) ppm for substoichiometric operation to about 70 ppm for 1.09 SR cases. The ammonia slip corresponding to the design SR of 1.02 ranged between 10 and 16 ppm. NO_x removal across the entire system, based on manual samples, averaged about 94%. Data from the most recent month available, June, showing inlet and outlet NO_x and removal efficiency is contained in Figures 3 and 4.

It should be noted that this test series was executed with SCR inlet temperatures below design by about 20°F. Additional test series around the SCR reactor are planned during the remainder of the project to fully characterize the effects of variations in load, inlet temperature, SR, and inlet NO_x on NO_x removal. Repetitious tests over the life of the project are also planned in order to document catalyst activity relative to operating time. Periodically small samples of the catalyst are removed and analyzed by the manufacturer, Haldor Topsøe, to further quantify variations in activity.

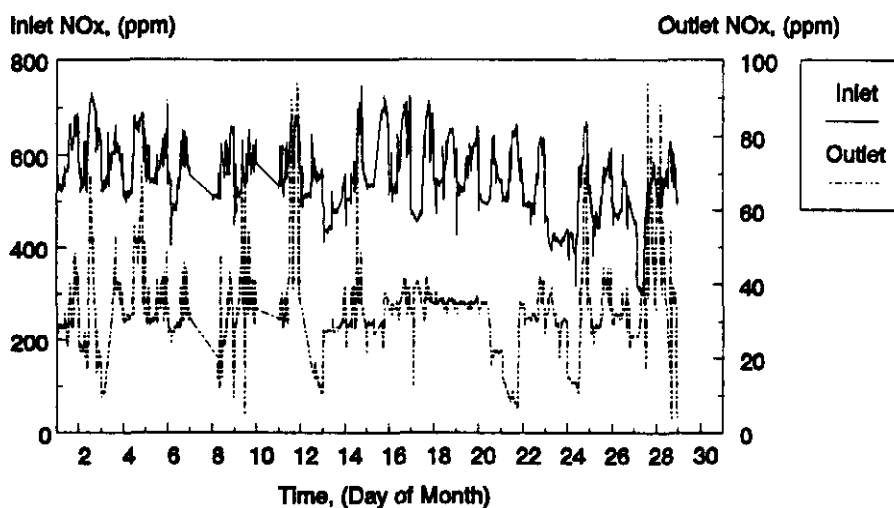


Figure 3
Inlet and Outlet NO_x Concentrations - June 1993

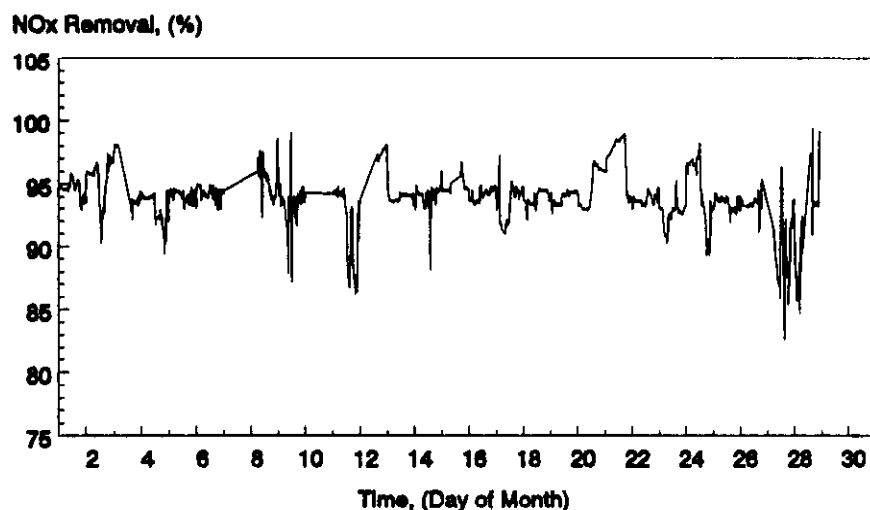


Figure 4
NOx Removal Efficiency - June 1993

The SCR system is very passive and has provided reliable, maintenance free operation. One equipment selection hurdle, however, was encountered during startup. The originally installed ammonia pump, which was of a diaphragm type, operated satisfactorily only at low ammonia flow rates. As the pump stroke was increased to provide additional flow, flashing occurred in the pump suction. Some modifications were made to the pump suction piping and ammonia storage tank operating level, but only minimal performance improvement was obtained. This problem was corrected by a change to a spur gear pump for ammonia pressurization. This pump selection has performed very well and allows the full range of design ammonia flow rates.

During normal operation of the plant, SCR system performance has been as expected with the exception of two developments resulting from the operation of other, upstream equipment. First, the low temperature zone at the inlet to the SCR reactor, discussed earlier, has necessitated the restriction of NH_3 addition in the affected area. This small, outboard zone, however, is a low mass flow region and has not affected NO_x removal significantly. The installation of a thermal mixing device during the next extended outage will allow the final optimization of the SCR system for NO_x removal and NH_3 consumption.

Second, higher than expected particulate emissions from the fabric filter have resulted in the accumulation of dust on the upper surface of the first SCR catalyst bed. This accumulation has been identified during planned inspections. Even though no performance degradation has resulted from this accumulation, the dust has been evacuated during these inspections.

SO₂ Removal

Sulfur dioxide removal in the SNOX Process is controlled by the efficiency of the SO₂ to SO₃ oxidation which occurs as the flue gas passes through the oxidation catalyst beds. The SO₂ Converter, which contains the catalyst, is a vessel constructed of high temperature, carbon steel containing four panels installed in parallel, each with two vertical beds. The beds are filled with Haldor Topsøe VK-WSA sulfuric acid catalyst. Excess amounts of catalyst exist in the top and bottom of the converter. The flue gas is distributed uniformly over the eight catalyst beds through five inlet nozzles. After passing through the catalyst beds, the flue gas is discharged through four outlet nozzles. Each outlet has a damper capable of stopping flow through the associated catalyst panel. The SO₂ Converter also has an associated Catalyst Screening System which is used to remove particulates from the catalyst periodically.

The catalyst is a vanadium-based oxidation catalyst in the shape of 0.4 inch O.D./0.16 inch I.D. x 0.35 inch rings. Due to the fact that the active compounds contained in the catalyst matrix are in a semi-molten state, most of the flyash entering the catalyst beds will be retained on the catalyst surface. For this reason, the catalyst must be removed from the vessel at periodic intervals to remove the flyash; the frequency of which will depend on the flyash loading.

To dedust the SO₂ oxidation catalyst when the SO₂ Converter differential pressure reaches a maximum level and restore the normal pressure drop, the Catalyst Screening System is operated. The major pieces of equipment involved in the cleaning system are two containers for catalyst transfer, one vibrating pan feeder to adjust the flow rate of catalyst to the screen, one vibrating screen to mechanically dedust the catalyst, one collection vessel for the catalyst sifting, and four capstan motors for catalyst container transfer throughout the system. The catalyst flow into the catalyst containers is controlled by pneumatic valves, one on the bottom of each catalyst bed.

Table 2

Flue Gas Flowrates in SO₂ Converter Outlet Ducts				
Duct	Volumetric Flow		Velocity	Deviation
	acfm	dscfm	fps	%
A	47,216	18,896	42.2	+ 0.73
B	48,608	19,458	43.4	+ 3.7
C	46,796	18,902	41.8	+ 0.76
D	43,944	17,777	39.2	- 5.2
Total	186,553	75,036		
Average	46,638	18,759	41.6	

Oxidation efficiency through the catalyst beds is controlled primarily by two factors - space velocity and bed temperature. Space velocity governs the amount of catalyst which is necessary at design flue gas flow conditions and gas and bed temperature must be high enough to "ignite" or activate the SO₂ oxidation reaction.

In the tests conducted to date, temperature and flow measurements have been taken for the four catalyst panels. In order to have uniform space velocity for each panel, the flue gas flow to each must also be uniform. Because an in-line, trim burner is used at the Niles SNOX plant, temperature distribution entering the panels was measured since uniformity can be more variable with this type of heat source. A tubular heater can also be employed in this location and will minimize the possibility of temperature maldistribution.

Table 2 lists results from the flow measurements and Table 3 contains the results from the temperature measurements. The flow measurements were made at the four outlet nozzles or ducts and temperature measurements were done at the five inlet

Table 3

Flue Gas Temperatures in SO₂ Converter Inlet Ducts		
Duct	Temperature Deg F	Deviation %
A	806	- 0.62
B	798	- 1.6
C	844	+ 4.1
D	801	- 1.2
E	804	- 0.86
Average	811	

nozzles or ducts. Flow through the four catalyst panels is acceptably uniform and all quantities are within 6% of the average. With respect to temperature, it is also uniform and the temperatures in the five inlet ducts are within about 4% of the average.

Table 4

Sulfur Dioxide Removal Efficiency			
Date	Inlet (ppm)	Outlet (ppm)	Efficiency (%)
12/18/92	1719	57.6	96.6
12/18/92	1880	68.0	96.4
12/18/92	1927	81.2	95.8

SO₂ concentrations at 3% O₂

Oxidation efficiency in the SO₂

Converter is measured by sampling for sulfur dioxide at the outlet of the WSA Condenser. Sulfur dioxide removal efficiency of the SNOX system is controlled by the oxidation efficiency of the SO₂ Converter. During particulate testing which was conducted in December of 1992, manual samples were also taken for inlet and outlet SO₂. These values are shown in Table 4. Removal efficiency was about 96% in these tests. Also, as was shown for the NO_x performance, SO₂ inlet and outlet values along with removal efficiency for the month of June are contained in Figures 5 and 6.

As has been mentioned, the surface of the SO₂ catalyst is tacky at operating temperature and will

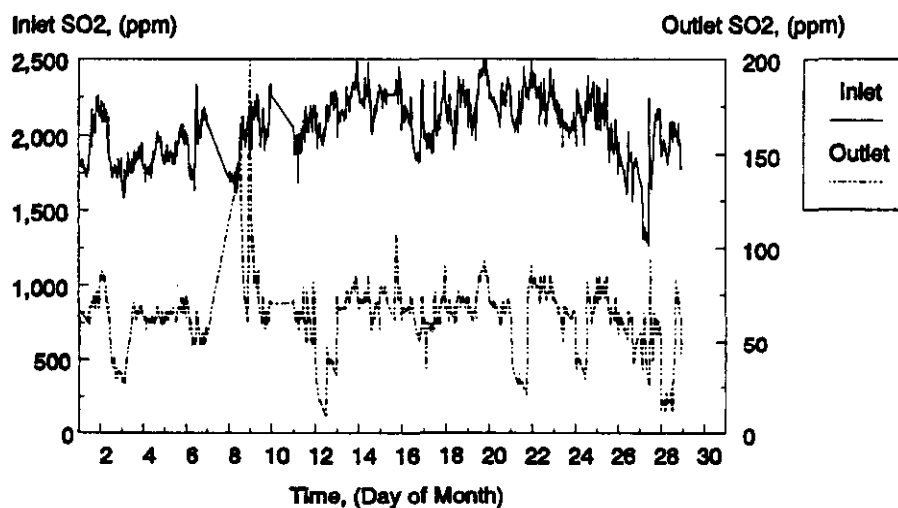


Figure 5
SO₂ Inlet and Outlet Concentrations - June 1993

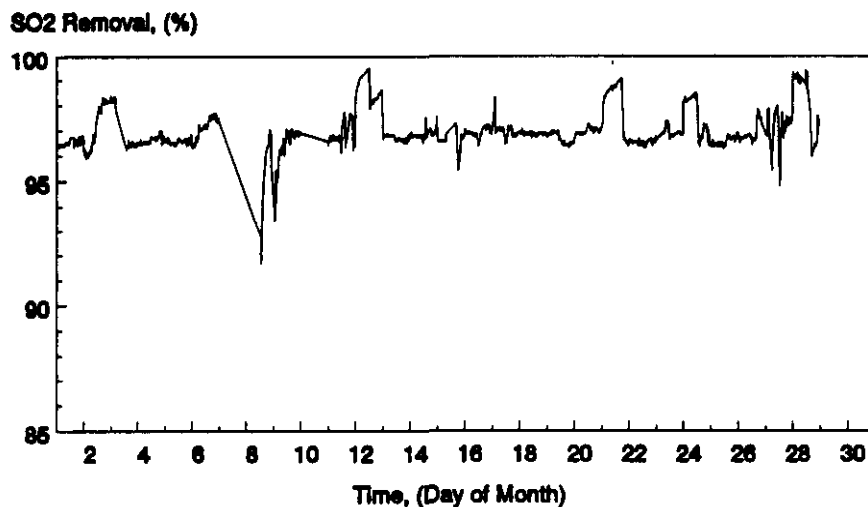


Figure 6
SO₂ Removal Efficiency - June 1993

remove a portion of the particulate matter which enters the catalyst beds. Clean catalyst beds will have a pressure drop of about 2-3 inches w.g. and are operated until the pressure drop exceeds 5 inches before they are dedusted. At a particulate loading of 0.0004 gr/dscf it was estimated that the catalyst would require cleaning about once a year based on the European pilot plant experience.

At the time of preparation of this report, June 1993, the system has operated on flue gas for about 5200 hours and the SO₂ Converter pressure drop is at 3-4 inches w.g. This is less than was expected given the higher than anticipated particulate loadings which have been entering the SO₂ Converter. This result may be due to the catalyst capturing less particulate than predicted, the settling of catalyst in the beds since start up of the unit, or unrepresentative particulate loading samples. When settling occurs, the top of the catalyst beds are open and some of the flue gas is bypassed. The converter beds were checked in April of 1993 and filled with catalyst. The beds had settled about 1 foot of their original 15 foot height.

With respect to the measured particulate loadings, some samples have had large particles on the filter which can cause false high values. While it is possible that baghouse emissions may have

been in the 0.003 to 0.004 gr/dscf range, it is unlikely that the values higher than these are representative. If loadings were very high ($> .008$ gr/dscf), the catalyst beds pressure drop would increase more rapidly than experienced.

Although catalyst bed pressure drop has not exceeded the limit of 5 inches w.g., one of the eight catalyst beds was emptied and put through the cleaning cycle in May of 1993 to verify equipment performance. All components performed correctly and the cleaning was successfully completed. This initial cleaning was performed with the unit cold and off line to check equipment, but subsequent dedusting will be performed with the unit on line; and the hot catalyst beds will be isolated, emptied, and cleaned.

During operation of the SNOX plant to date, one mechanical component of the SO_2 Converter has required replacement and redesign. At the four outlets of the converter, expansion joints are employed to connect to the main header. Given the high temperature (800°F), SO_3 content of the flue gas, and static pressure of 20 inches w.g.; these expansion joints must handle a severe environment. The initial joints employed a PTFE coated fiberglass material and were insulated on the outside to prevent condensation of sulfuric acid on the inner surface of the joints. However, temperatures were too high for the joint material and eventually caused failure.

The second design employed was a metal foil joint which was also insulated on the outside. These joints could not handle the degree of mating flange movement and the foil ripped soon after installation. At this time a more elaborate and expensive solution was considered based on the Danish SNOX plant experience. A joint purged with hot air and constructed with an internal permeable material is used in this plant. The seal is made with PTFE based materials on the outside which are not exposed to flue gas temperature.

Before this solution was attempted at Niles, it was decided to evaluate another conventional joint with insulation on the inside of the PTFE coated sealing membrane. In this way, the PTFE can operate below its degradation temperature and any flue gas leakage past the insulation will not damage the joint if any condensation occurs. These joints have been in service about 800 hours

at this time and have not had any early problems.

Sulfuric Acid Condensation

After the flue gas has passed through the SO₂ Converter which has oxidized greater than 95% of the incoming SO₂ to SO₃, the gas must be cooled to induce the condensation of sulfuric acid. This cooling must be performed strategically as high SO₃ concentrations can represent a very aggressive atmosphere should condensation occur in the presence of unsuitable materials of construction. Depending on the actual concentrations of SO₃ and water, the acid dewpoint of this flue gas stream is in the range of 400°F.

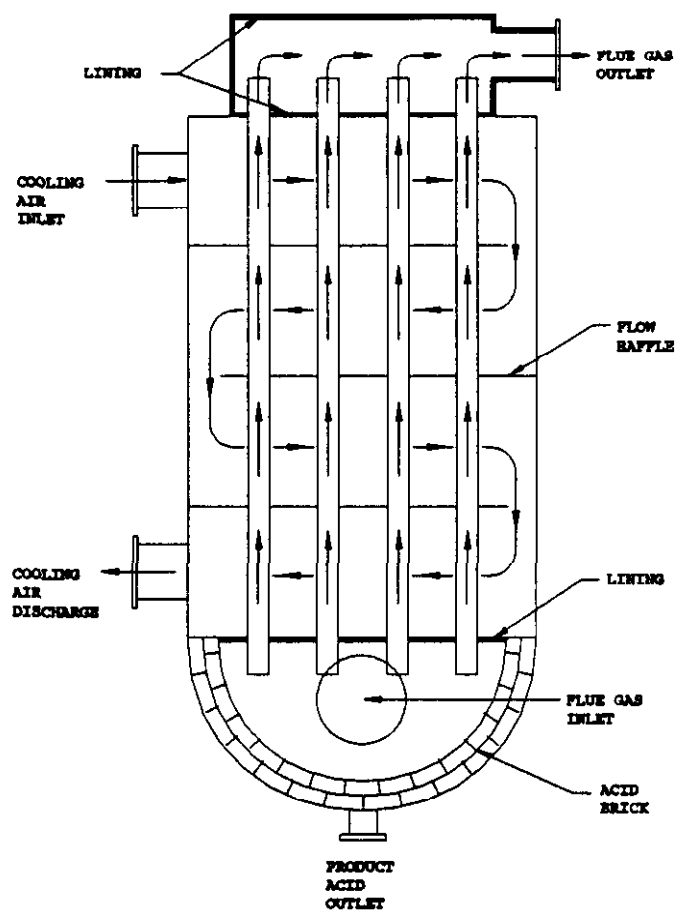


Figure 7
WSA Condenser

The cooling of the gas is performed through two pieces of equipment - first the hot side of the gas/gas heat exchanger and then the WSA Condenser. As heat is transferred to the SCR reactor inlet stream via the GGH, the gas cools to about 510°F. This temperature change drives most of the SO₃ to hydrate with available water to form H₂SO₄ vapor. The precooled gas enters the bottom of the condenser which is lined with an acid resistant brick. The gas then flows up through the interior of borosilicate glass tubes. Ambient air is passed across the exterior of the glass tubes countercurrently to the flue gas flow. In this manner the fluegas is cooled to about 210°F and the cooling air is heated to about 400°F. Figure 7 illustrates the gas flows through an individual WSA Condenser compartment.

During the flue gas cooling, sulfuric acid vapor condenses in a filmwise fashion on the inner

walls of the tubes and drains into the acid collection trough in the bottom of the condenser. The design of this piece of equipment allows for very high collection efficiency of $\text{SO}_3/\text{H}_2\text{SO}_4$ in the gas stream with outlet concentrations of between 2 and 5 ppm of aerosol mist. This concentration is below the SO_3 normally emitted in the flue gas of boilers burning medium to high sulfur coal (5 - 20 ppm). The collected acid is of very high quality and concentration, 94 to 98 wt.% depending on the process conditions of the particular installation.

The WSA Condenser at Niles consists of ten compartments in a 2 x 5 arrangement, each with 720 glass tubes. The lower portion of the lower tube sheet, the upper portion of the upper tube sheet, and the outlet hoods are lined with fluoropolymers. Thus, all materials of construction in contact with the flue gas are acid resistant. It should be noted that the WSA Condenser at Niles is of commercial, full scale size. Larger gas flowrates merely require multiple condenser modules. One exception is that these modules are now commonly offered in a 2 by 6 arrangement, i.e. 12 compartments per condenser module.

The process performance of a WSA Condenser is marked by three criteria:

- Complete condensation of H_2SO_4 with minimal aerosol mist carryover,
- High quality, high concentration (> 93 wt. %) acid product with water clarity,
- A minimum flowrate of discharge cooling air at a maximum temperature to facilitate efficient energy recovery in the furnace.

Baseline testing of the WSA Condenser of Niles was executed early in the Testing Phase of the demonstration. This testing focused on the fluegas effluent and acid product streams. Acid mist carryover was measured to be at 2 to 5 ppm depending on plant load and operating temperatures around the condenser. Mass balances around the system have yielded tight closure for sulfur compounds. The sulfuric acid product from the process has consistently been of 94 to 95 wt.% concentration with water clarity. The acid has been analyzed regularly for trace compounds to compare with commercial acid specifications. Results are given in the last report section. All acid product from this facility has been purchased by a local acid distributor and utilized by local industry.

Although the heat energy recovered in the condenser cooling air at Niles is not used for

preheated furnace combustion air as will be the case for fullscale applications, the cooling air flowrates and temperatures have been on design and as expected. As the testing phase progresses, a full parametric study of the WSA Condenser operation will be performed in order to fully verify all design criteria.

The airside, inlet flue gas, and outlet flue gas areas of the condenser module have been inspected regularly during scheduled plant outages. Of key concern is the identification of potential corrosion sites which might result in mechanical damage. Thus far, all coverings such as the acid brick and fluoropolymer linings of the upper and lower tube sheets and outlet hoods have shown no compromise in integrity. All PTFE components and the 7200 glass tubes, as would be expected, have been virtually unaffected by the aggressive atmosphere. A small fraction, about 0.17%, of the tubes have broken due to the combination of localized misalignment and thermal cycling. This small fraction of tube breakage is expected and designed for in the sizing of the condenser. Furthermore, this quantity is consistent with the breakage rate experienced at other SNOX installations and does not warrant replacement or correction.

Acid Production

Sulfuric acid concentration and composition has also been excellent and has met or exceeded the requirements of the Federal Specification for Class 1 for species analyzed to date. Results from the analyses are shown in Table 5 along with the values from the federal specification. Three components, sulfurous acid (H_2SO_3), antimony and

Table 5

**Typical Niles SNOX Plant Acid Composition Versus
U.S. Specification O-S-801E**

	Spec.	Niles
Concentration (%)	93.2	93.5
H_2SO_3 (ppmw)	40	NA
Iron (ppmw)	50	10
Copper (ppmw)	50	< 1
Zinc (ppmw)	40	< 1
Arsenic (ppmw)	1	0.4
Antimony (ppmw)	1	NA
Selenium (ppmw)	20	1.4
Nickel (ppmw)	1	< 1
Manganese (ppmw)	0.2	< 1
Nitrate (ppmw)	5	*
Ammonium (ppmw)	10	3
Chloride (ppmw)	10	2.5

NA - Not Analyzed, * - Resolving analysis

nitrites, have not been documented at this time. Sulfurous acid and antimony were inadvertently omitted from the analytical laboratory's specification initially, and the nitrite values obtained to date are being evaluated as to correct analytical technique.

During design and construction of the SNOX Demonstration Project at Niles Station, arrangements were made with a sulfuric acid supplier to purchase and distribute the acid from the plant once operation began. The supplier, PVS Chemicals, is a large regional marketer and producer of sulfuric acid serving the industrial Midwest in New York, Ohio, Michigan and Illinois. This material has been sold primarily to the agriculture industry for the production of di-ammonium phosphate fertilizer, and to the steel industry for pickling. As of June 1993, approximately 3400 tons have been produced and distributed as shown in Figure 8.

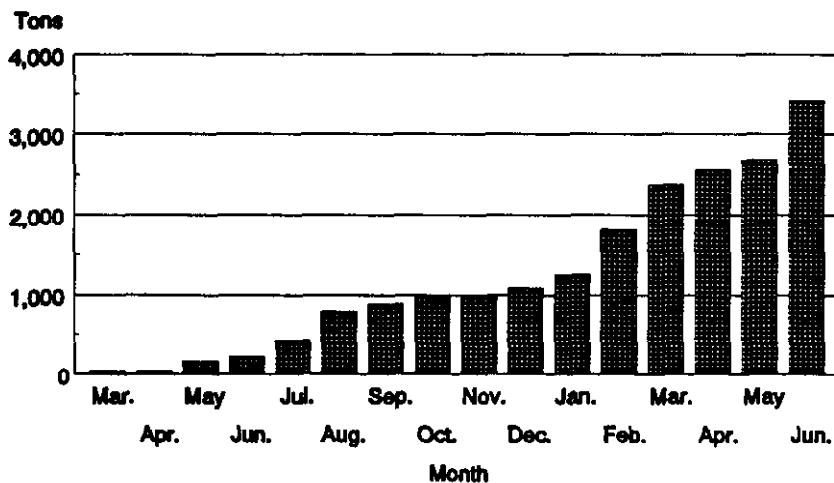


Figure 8
Cumulative Acid Production

Preliminary Performance and Operating Results from the Integrated Dry NO_x/SO₂ Emissions Control System

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ABSTRACT

The Integrated Dry NO_x/SO₂ Emissions Control System was installed at Public Service Company of Colorado's Arapahoe 4 generating station in 1992 in cooperation with the U.S. Department of Energy (DOE) and the Electric Power Research Institute (EPRI). This full scale 100 MWe demonstration combines low-NO_x burners, overfire air, and selective non-catalytic reduction (SNCR) for NO_x control and dry sorbent injection with humidification for SO₂ control. Operation and testing of the Integrated Dry NO_x/SO₂ Emissions Control System began in August 1992 and will continue through mid 1994. Preliminary results of the NO_x control technologies show that the original system goal of 70% NO_x removal has been easily met and that NO_x removals of up to 80% are possible at full load with the combustion and SNCR systems. Testing of the dry sorbent injection system with low sulfur coal began in April 1993 using a calcium-based reagent. A maximum SO₂ removal of 40% has been achieved with duct injection of commercial calcium hydroxide and humidification to a 25°F approach to saturation. Sodium-based dry sorbent injection is expected to achieved up to a 70% SO₂ reduction.

INTRODUCTION

There are many technologies for NO_x reduction but the four that are currently receiving the most attention are low-NO_x burners, staged combustion using overfire air, selective catalytic reduction (SCR), and selective non-catalytic reduction (SNCR).

Various government and industry sponsored demonstration programs have been conducted showing that low-NO_x burners with or without overfire air can economically and efficiently reduce NO_x emissions of wall- and tangentially-fired boilers. However, no research or demonstration projects have been completed on the less popular top-fired boiler. There are only a small number of top-fired boilers in the United States but PSCC operates seven of these boilers in the Denver Metro area. Characteristics of a top-fired boiler are a small furnace with a very turbulent flame. These conditions generally lead to much higher NO_x emissions than on the more common wall- and tangentially-fired boiler.

SCR has been proven effective at reducing NO_x emissions in Germany and Japan but has not been successfully demonstrated on U.S. coal-fired utility boilers. This technology is generally the most expensive technology for reducing NO_x emissions although estimated costs are decreasing rapidly. The major advantage of SCR is that NO_x reduction, with a proper design, is higher than other competing technologies. SCR has the disadvantages of requiring considerable space in a retrofit situation and the user must be aware of the possible waste disposal concerns of the spent catalyst.

SNCR is substantially less expensive to install than the competing SCR but it cannot attain as high NO_x removals. SNCR has been successfully demonstrated on gas-fired boilers in the United States, industrial boilers, and has limited experience in Europe on other fuels. However, previous to this project, the technology had not been demonstrated on a U.S. coal-fired utility boiler. While less expensive than SCR, SNCR has the disadvantage of possible higher ammonia slips and N₂O generation.

A demonstration of the most promising of these technologies was required to show that high efficiency NO_x removal can be retrofit to top-fired units. The combination of the latest generation low-NO_x burners, overfire air, and SNCR offers the potential to obtain very high NO_x removals at potentially lower capital and operating costs than SCR alone. The demonstration is required as this is a first-use technology and cannot be commercially developed without a successful demonstration.

There are many technologies for reducing SO₂ emissions on utility boilers. The most popular and successful of these is the standard wet scrubber. Many variations and improvements have been made to wet scrubbers over the years and the units are economically achieving high efficiency SO₂ reduction on high sulfur coals. However, scrubbers have high initial cost and can be difficult to retrofit to older units which have limited available land area. In addition, older units often operate at reduced capacity factors and thus initial costs greatly affect the life cycle costs. On these units, other technologies have been proposed that generally have lower initial cost but higher operating cost. At reduced baseline SO₂ levels, the initial equipment cost can substantially increase the cost per ton of SO₂ removed.

One of these lower initial cost technologies is dry sorbent injection (DSI). In this process, either calcium hydroxide or sodium-based reagent is injected into the flue gas duct before the particulate control equipment. The solids react with gaseous sulfur oxides in the flue gas and convert them to a solid product. The solids are removed from the particulate

control device and landfilled. Humidification of the flue gas is required with calcium hydroxide in order to increase reagent utilization. DSI using calcium had been demonstrated on one full scale Eastern unit with high sulfur coal but has not been proven at very low initial SO₂ concentrations. Sodium-based reagent injection offers the advantage of not requiring humidification to obtain high SO₂ removal efficiencies. However, testing on large scale units has found that sodium injection converts some of the NO in the flue gas into NO₂. While the overall NO_x is slightly reduced, the higher NO₂ can cause a visible brown/orange plume at the stack. Testing has shown that the visible plume can be reduced or eliminated if the SO₂ reduction reaction occurs in the presence of ammonia-based compounds. Another form of DSI injects calcium hydroxide upstream of the economizer section of the boiler. Pilot scale testing at temperatures below 1200°F has shown good SO₂ removal efficiencies but no full scale testing has been completed in the United States. While some types of DSI have been previously demonstrated, not all of the problems have been solved with the technology. A successful full scale demonstration is required to allow commercialization of these technologies.

Public Service Company of Colorado (PSCC) is an investor owned utility serving much of Colorado. PSCC has strived to be an environmentally responsible corporation and has tested and retrofit many pollution control technologies to its coal fired power plants. The Company decided that a demonstration of NO_x and SO₂ removal technologies was important on a top-fired unit and began assembly of a competent team to prepare a proposal for Round 3 of the U.S. Department of Energy's (DOE) Clean Coal Technology Program. Table 1 shows the participants involved in the project and their major responsibilities. This project, called the Integrated Dry NO_x/SO₂ Emissions Control System, was the first demonstration of low-NO_x burners, overfire air, and urea-based SNCR for a top-fired utility boiler. The project includes the use of dry sorbent injection using both sodium- and calcium-based reagents for SO₂ control.

TABLE 1 - Project Participants

Participant	Function
Public Service Company of Colorado	Project Manager, Design, Construction, Funding
Department of Energy	Funding
Electric Power Research Institute	Funding, Technical Assistance
Babcock & Wilcox	Combustion Modifications and Humidification System Design, Supply, and Erection
Noell, Inc	Urea Injection System Design, Supply
Fossil Energy Research Corporation	Testing
Stone & Webster Engineering Corporation	General Engineering and Design
Western Research Institute	Waste Analysis and Research
Colorado School of Mines	Sodium Injection Process Research

UNIT DESCRIPTION

PSCC selected Arapahoe Unit 4 as the demonstration site for this project. The station has four top-fired boilers supplied by Babcock and Wilcox in the early 1950s. Arapahoe 4 is a

nominal 100 MWe unit that began operation in September 1955. The boiler fires a low sulfur (0.4%) Colorado bituminous coal as its main fuel source but also has 100% natural gas capability. While Arapahoe 4 is an older unit with over 35 years of operation, PSCC plans to continue unit operation well into the next century.

This small turbulent boiler was an efficient coal combustor but was also effective at generating high NO_x emissions. Baseline NO_x levels for this boiler were approximately 1.10 lb/MMBtu. The pulverized coal was injected through twelve intertube burners located in the roof of the boiler as shown in Figure 1. The intertube burner is not comparable to a more common wall-fired burner. It consists of a splitter box that separates into 20 smaller nozzles that inject the coal and primary air mixture evenly across the furnace roof. Secondary air was injected beside the coal nozzles and the system contained no adjustments to control the rate of secondary air and fuel mixing.

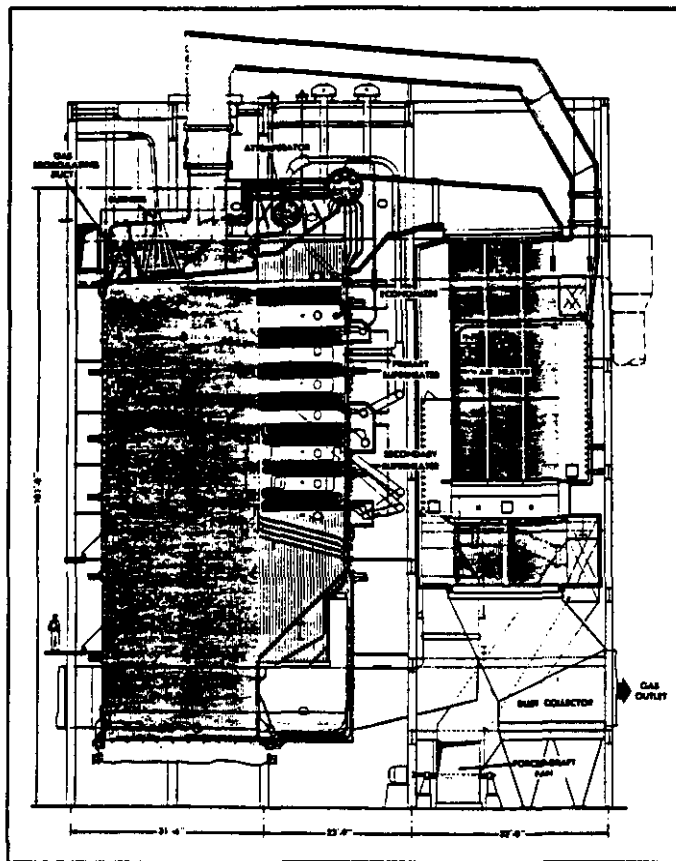


Figure 1 - Boiler Elevation

PROJECT DESCRIPTION

The Integrated Dry NO_x/SO_2 Emissions Control System consists of five major control technologies that are combined to form an integrated system to control both NO_x and SO_2 emissions. NO_x reduction is obtained through the use of low- NO_x burners, overfire air, and urea injection while dry sorbent injection using either sodium- or calcium-based reagents with humidification is used to control SO_2 emissions. The project goal is to provide up to a 70% reduction of both NO_x and SO_2 emissions. The combustion modifications were expected to reduce NO_x by 50%, with the expectation that the SNCR system would provide the remaining 20% reduction. Dry Sorbent Injection was expected to provide 50% removal of the SO_2 emissions while using calcium-based reagents. As sodium is much more reactive than calcium, it was expected to provide SO_2 removals of up to 70%. Figure 2 shows a simplified schematic of the Integrated Dry NO_x/SO_2 Emissions Control System as implemented at Arapahoe 4.

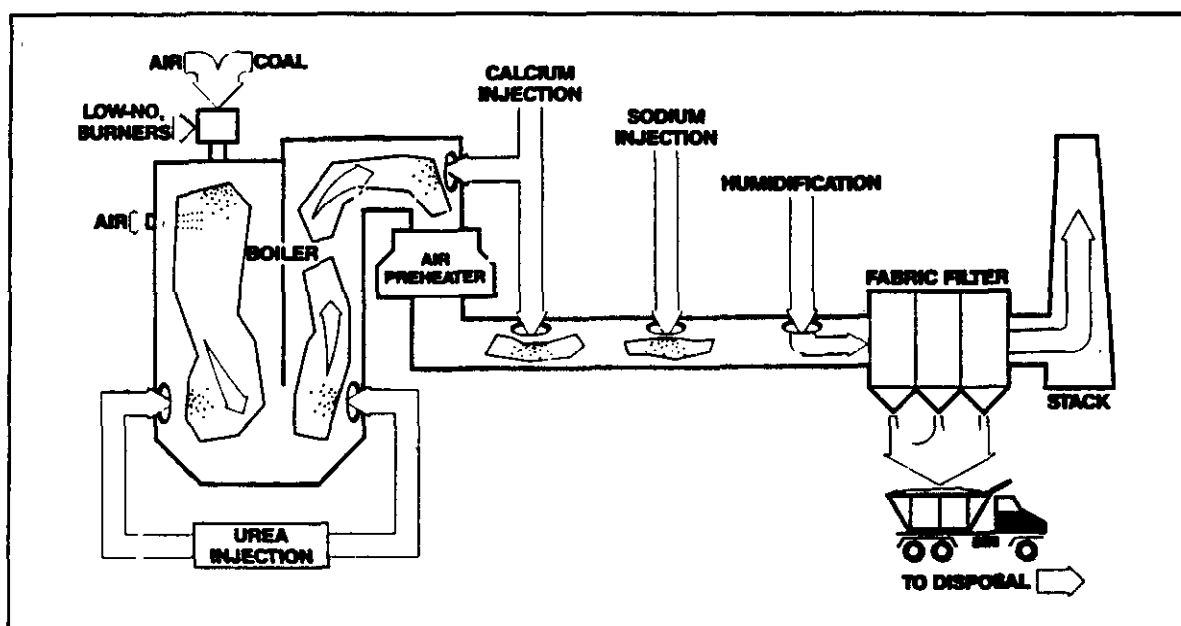


Figure 2 - Process Flow Diagram

The total estimated cost of this innovative demonstration project is estimated at \$27,411,000. The project cost breakdown is shown in Table 2. Funding is being provided by the DOE (50.0%), PSCC (43.7%), and EPRI (6.3%). The DOE funding is being provided as a zero interest loan and is expected to be paid back from the proceeds obtained during commercialization of the technology over a 20 year period from the conclusion of the demonstration project.

Table 2 - Project Cost

Task	Estimated Cost
Pre-Award	\$358,000
Design	\$3,171,000
Equipment Procurement	\$8,445,000
Construction	\$8,292,000
Operations & Maintenance	\$6,600,000
TOTAL	\$27,411,000

Low-NO_x Burners

Babcock and Wilcox (B&W) was selected to provide the low-NO_x burners for the Arapahoe 4 project. B&W's DRB-XCL® (Dual Register Burner-aXially Controlled Low-NO_x) burner had been successfully used to reduced NO_x emissions on wall-fired boilers but had never

been used in a vertically-fired furnace. The burner has two main features which limit NO_x formation as shown in Figure 3, a simplified schematic of the burner. The first feature is a sliding air damper. In many older burners a single register is used to control both total secondary air flow to the burner and also the rate of air/fuel mixing. The use of the sliding damper in the DRB-XCL® separates the functions and allows the secondary air flow to be controlled independently of the spin. The burner includes a 30 point pitot tube grid so that a relative indication of the secondary air flow at each burner is possible. The second feature of the burner is dual registers. The most important variable in the control of NO_x is the rate at which oxygen is mixed with the fuel. The ability to adjust both inner and outer registers provides more control over the rate of combustion and thus the amount of NO_x formed.

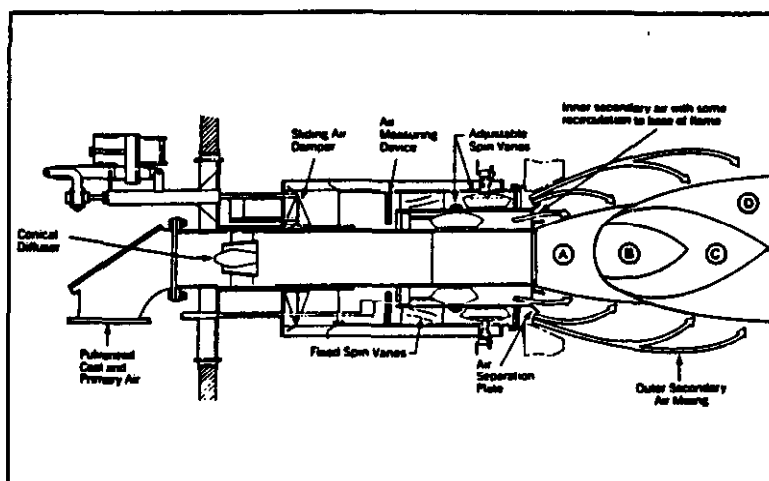


Figure 3 - B&W DRB-XCL® Burner

A low- NO_x retrofit on a top-fired unit is much more involved than modifications to most wall- or tangential-fired units. At Arapahoe Unit 4, the modifications required the replacement of all boiler roof tubes to provide the circular openings required for a "normal" burner. The burners were placed in 4 rows of 3 burners. One major design problem of the retrofit was locating the secondary air ductwork. The secondary air duct originally entered the windbox at the rear of the furnace roof. The new burners required significantly more space than the intertube burners and there are now four burners where the secondary air duct was originally placed. Smaller ductwork was added to the furnace roof and the remaining combustion air was added through an abandoned gas recirculation duct that entered the front of the furnace.

The burner retrofit included new Class I gas ignitors. Arapahoe 4 originally included the ability to fire 100% natural gas. While coal is used as the main fuel, natural gas is used on occasion to provide load when pulverizers or other equipment are out of service. The natural gas firing was maintained with the DRB-XCL® burners by the use of a gas ring header located at the tip of the burner. No modifications were made to the original Riley pulverizers, although a new electronic variable speed feeder drive was added to provide more consistent coal feed.

Overfire Air

While low- NO_x burners alone have proven to be effective for reducing NO_x , combustion staging can further reduce NO_x emissions. Overfire air delays combustion by redirecting a portion of the secondary air downstream of the main combustion zone. As the initial

combustion occurs at lower stoichiometric ratios, less NO_x is formed. At Arapahoe 4 three B&W dual zone NO_x Ports were added to each side of the furnace approximately 20 feet below the boiler roof. These ports can inject up to 25% of the total combustion air through the furnace sidewalls. The NO_x ports separate the overfire air into two streams as shown in Figure 4. The outer area of the port contains adjustable registers that can be used to spread the overfire air next to the wall. The center area of the port uses a sliding disk damper to control air flow. This core zone injects a high velocity jet across the furnace toward the division wall. This two stage air injection allows for faster mixing and more equal distribution of the air and combustion gases in the furnace.

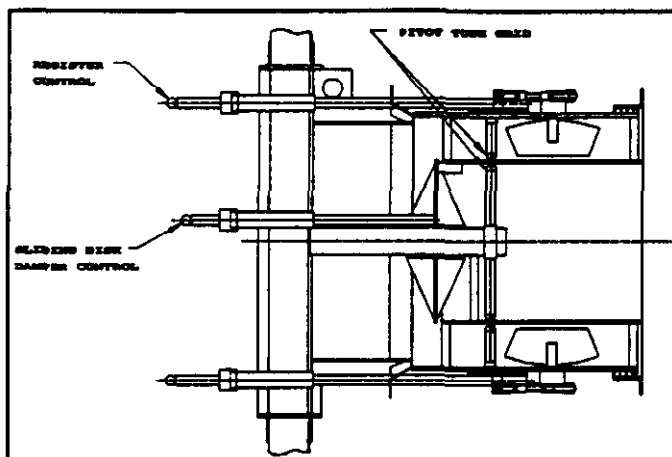


Figure 4 - B&W dual zone NO_x port

The NO_x ports are located on each side of the furnace in a small windbox. New ductwork was added that directs secondary air from the boiler roof to the overfire air windbox. Each of the ducts that supply the overfire air windboxes contains an opposed blade louver damper to control air flow. The ducts also contain a pitot tube grid with a flow straightener to measure total overfire air flow.

Selective Non-Catalytic Reduction

The purpose of the SNCR system at Arapahoe was to further reduce the final NO_x emissions obtained with the combustion modification so that the goal of 70% NO_x removal could be achieved. Urea was selected as the base chemical for the SNCR system, because urea, unlike either aqueous or anhydrous ammonia, is not a toxic chemical. Urea injection is a simple process. A liquid solution of urea is injected into the boiler. The urea decomposes at approximately 1700 to 1900°F and then reacts with NO_x forming primarily nitrogen and water. The disadvantage of urea injection, as with any SNCR chemical, is that the process is very temperature sensitive. If the temperature is too high, some urea can be converted to NO_x . If the temperature is too low, more of the urea is converted to ammonia, which becomes an unacceptable new pollutant.

PSCC selected Noell, Inc. to design and supply the urea-based SNCR system. Figure 5 shows a simplified flow diagram of the system as implemented at Arapahoe Unit 4.

During original testing of the urea-based SNCR system, it was found that NO_x reductions at low load were less than expected. A short term test using aqueous ammonia achieved greater NO_x reduction than urea. Although ammonia was more effective than urea, it remained desirable to store urea due to safety concerns. A system was installed that allows on-line conversion of urea into ammonia compounds.

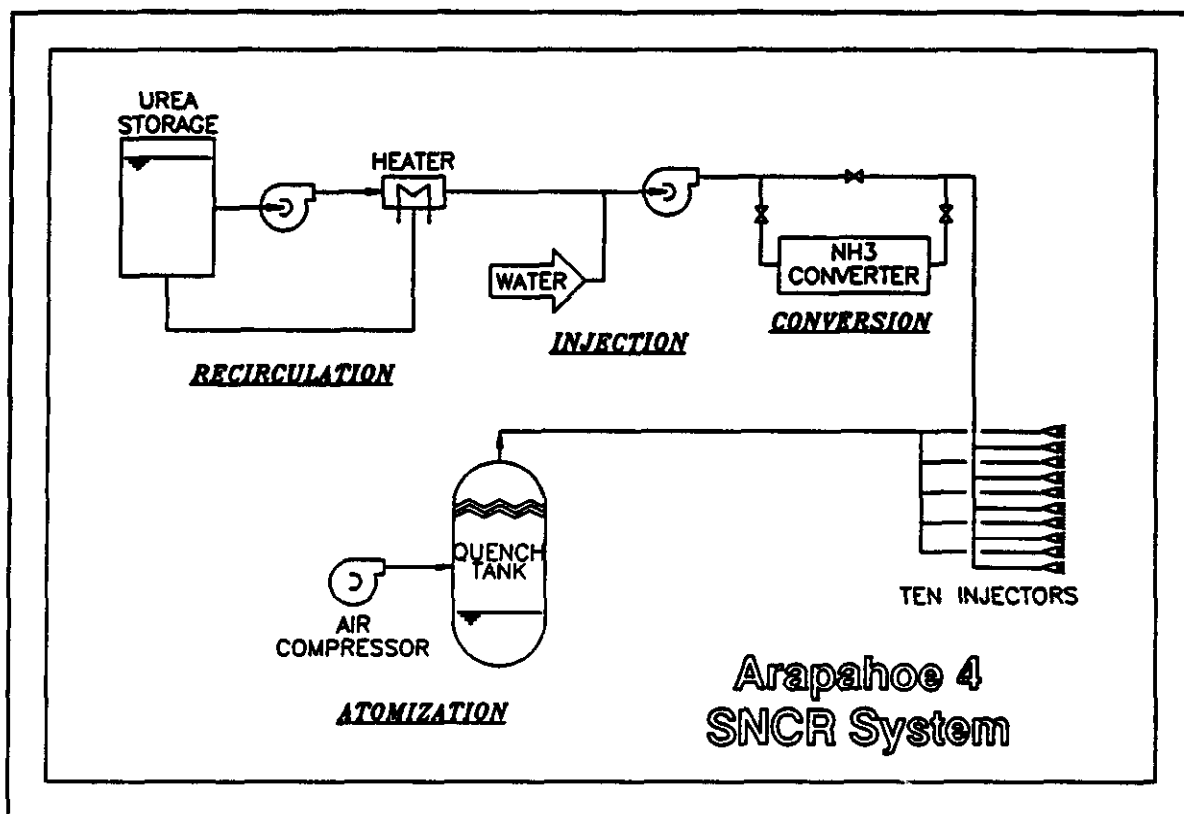


Figure 5 - SNCR Flow Diagram

The SNCR system at Arapahoe Unit 4 uses Noell's proprietary dual fluid injection nozzles to distribute the chemical uniformly into the boiler. A centrifugal compressor is used to supply a large volume of medium pressure air to the injection nozzles to help atomize the solution and rapidly mix the chemical with the flue gas.

Dry Sorbent Injection

A combination of dry technologies will be demonstrated at Arapahoe 4 to reduce SO₂ emissions. PSCC designed and installed a dry sorbent injection system that can inject either calcium- or sodium-based reagents into the flue gas upstream of the fabric filter. Figure 6 shows a simplified flow diagram of the equipment. The reagent is fed through a volumetric feeder into a pneumatic conveying system. The air and material then pass through a pulverizer where the material can be pulverized to approximately 90% - 400 U.S. Standard mesh. The material is then conveyed to the duct and evenly injected into the flue gas. A bypass can be installed to convey the material into the boiler upstream of the economizer in a region where the flue gas temperature is approximately 1000°F.

While significant SO₂ reductions can be achieved with sodium-based reagent, calcium hydroxide is less reactive. In order to improve SO₂ removal with calcium hydroxide, a humidification system has been installed. The system was designed by B&W and includes 84 I-Jet humidification nozzles to inject up to 80 gpm of water into the flue gas ductwork. The humidifier is located approximately 100 feet ahead of the fabric filter and there is no

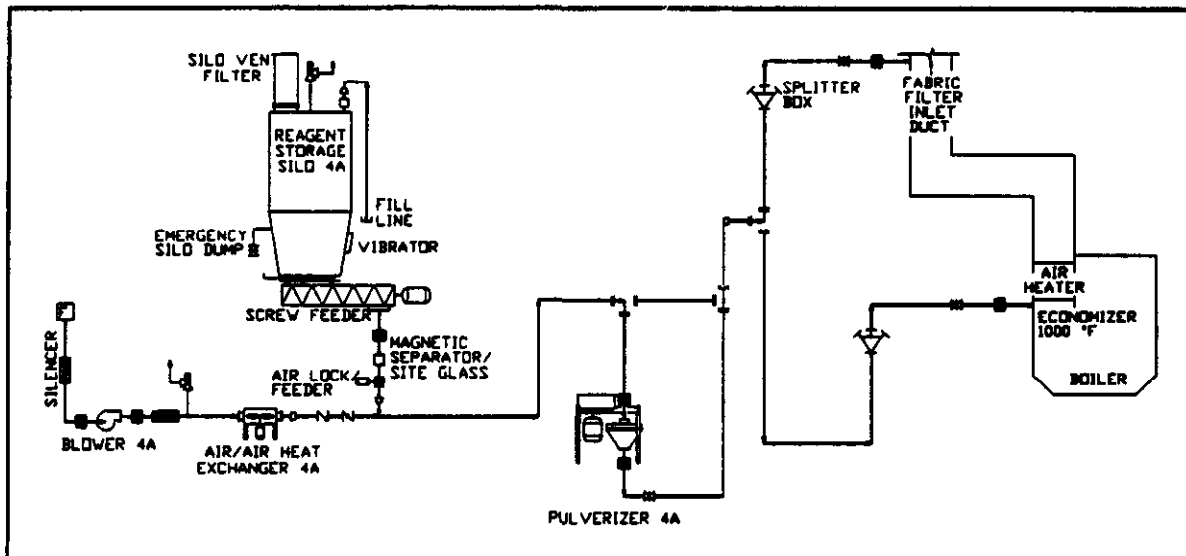


Figure 6 - Dry Sorbent Injection Flow Diagram

bypass duct. Although the system is designed to achieve a 20°F approach to saturation, it is not expected to operate the humidifier below a 40°F approach to saturation to protect the fabric filter.

Balance of Plant

In addition to the major environmental equipment, the project also included required upgrades to the existing plant. Arapahoe 4 originally used a Bailey pneumatic control system with limited controls for burner management. Due to the complexity of the retrofit, a new distributed control system was required to control the boiler and other pollution control equipment added as part of the project. The flyash collection system was also converted from a wet to a dry collection system to allow dry collection of the injection waste products. A Continuous Emission Monitoring (CEM) system was installed at Arapahoe Unit 4 to collect data for the extensive test program. This monitor allows continuous measurements of N_2O , NH_3 , NO_2 , and H_2O in addition to the more common pollutant measurements.

PROJECT SCHEDULE

The Integrated Dry NO_x/SO_2 Emissions Control System began with selection by the DOE in December 1989. Negotiations for the project were finalized with approval of the Cooperative Agreement on March 11, 1991. Construction began in July 1991 and was completed in August 1992. Due to the many different technologies included in the Integrated Dry NO_x/SO_2 Emissions Control System, the test program includes individual parametric tests of each of the individual systems during the period August 1992 through October 1993. Longer term testing of the optimized integrated system will continue through mid 1994 and project completion is scheduled with the Final Report due in November 1994. Table 3 shows the project schedule.

TABLE 3 - Project Schedule

	1991	1992	1993	1994
Cooperative Agreement Approval	■			
Boiler Baseline Testing		■		
Urea Injection Installation	■	■		
Initial Urea Testing		■		
Combustion Modifications		■		
Combustion Testing		■		
Ammonia Conversion Installation		■		
Urea Testing			■	
Dry Reagent Testing			■	
Integrated Testing			■	
High Sulfur Coal Testing				■
Final Report				■

PRELIMINARY RESULTS

Fossil Energy Research Corporation (FERCo) of Laguna Hills, California was selected to perform all testing of the Integrated Dry NO_x/SO₂ Emissions Control System. Currently the individual testing of the low-NO_x burners, overfire air, urea injection, calcium duct injection, and calcium economizer injection has been completed. Sodium duct injection testing will begin in July 1993 and continue through September 1993. Testing of the complete integrated system will continue through mid 1994 with up to four weeks of testing on a high sulfur (2.5%) coal. In addition to efficiency and emissions measurements, four tests will be conducted to determine baseline and removal capabilities of the system for many of the common air toxic emissions. Although all data have not been reviewed, some preliminary results of the individual technologies comprising the Integrated Dry NO_x/SO₂ Emissions Control System is available.

Combustion Modifications

Figure 7 shows the original baseline NO_x emissions compared to the tuned post-combustion retrofit emissions. Baseline NO_x emissions for the unit before the retrofit were nearly uniform across the load range at approximately 800 ppmc (Corrected to 3% O₂, dry) or about 1.10 lb/MMBtu. The combination of low-NO_x burners and overfire air have greatly reduced NO_x emissions. The post-retrofit NO_x emissions are shown for two staging configurations, maximum and minimum overfire air.

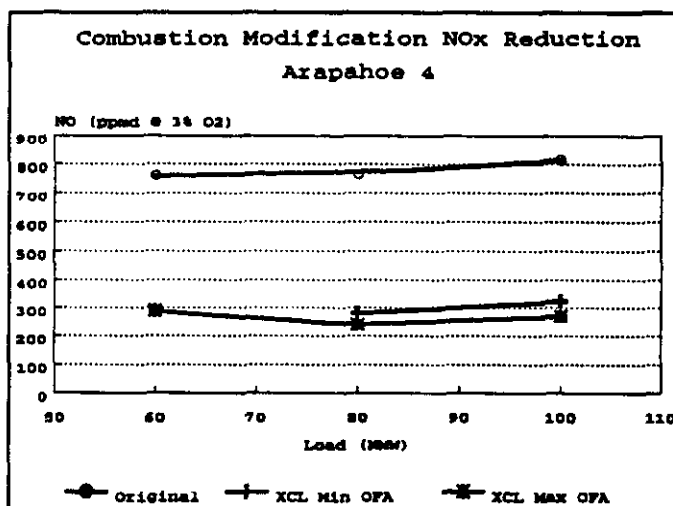


Figure 7 - NO_x Comparison

With maximum overfire air, approximately 25% of the total combustion air is introduced through the overfire air ports at full load. With minimum overfire air, approximately 15% of the total combustion air is introduced as overfire air. It is impossible to eliminate the overfire air as the ports are located in a very hot section of the boiler and damage would result at lower air flows due to reduced cooling. With maximum overfire air, the NO_x reduction varies from 62 to 69% across the load range. With minimum overfire air, NO_x reduction is reduced slightly to 60 to 63%.

Low- NO_x combustion modifications often increase flyash unburned carbon and increase carbon monoxide emissions. Figure 8 shows a comparison of unburned carbon in the flyash before and after the combustion modifications. Figure 9 shows a similar figure for CO emissions. Flyash unburned carbon is basically unchanged from the baseline levels and does not appear to be affected by the amount of overfire air. CO emissions are comparable to the baseline levels with maximum overfire air and increase slightly when the overfire air is reduced to the minimum value.

Overfire Air

Figure 10 shows data at a constant excess air level for two different loads. Overfire air flow is shown as a percentage of the total combustion air. The data indicate a slight decrease in NO_x as the overfire air flow is increased but NO_x reduction is less than generally expected. At 100 MWe, NO_x is reduced approximately 10% as overfire air is increased from 15 to 25%. The NO_x reduction is only approximately 8% at the 80 MWe load. It

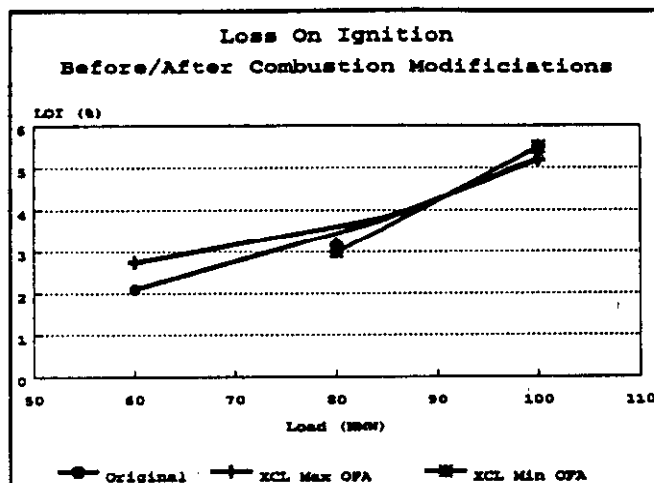


Figure 8 - Loss on Ignition

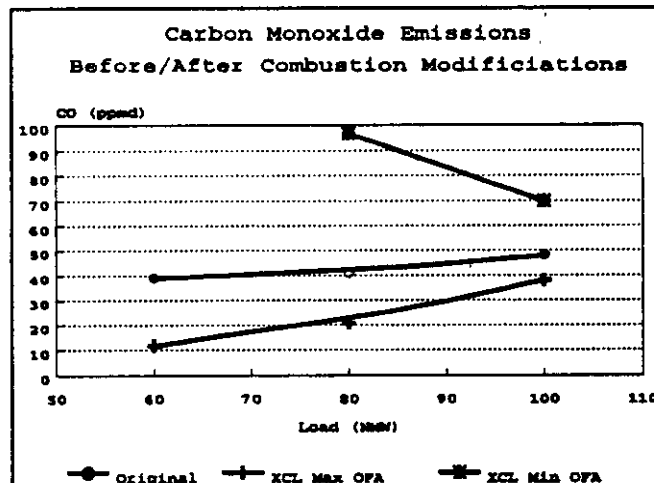


Figure 9 - Carbon Monoxide

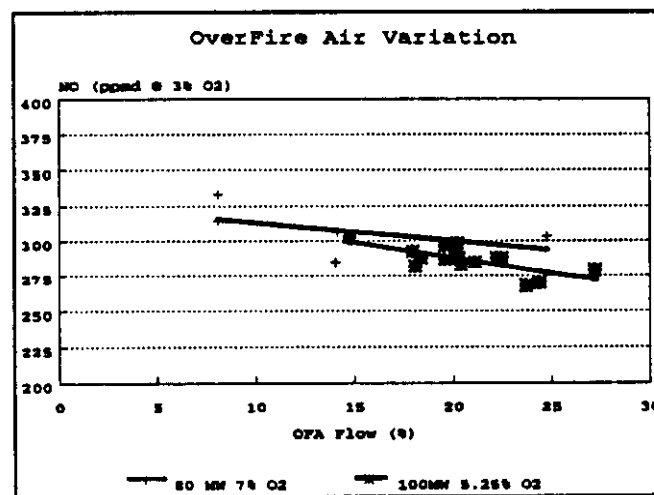


Figure 10 - Overfire Air Variation

is impossible to operate at 0% overfire air to determine the total effect of overfire air, but it appears that the low- NO_x burners are responsible for the majority of the NO_x reduction.

It appears that increasing overfire may have a positive combustion affect on top-fired units at low excess air operating conditions. At Arapahoe 4, no significant correlation could be found for either unburned carbon or CO emissions at reduced loads. This is due to the increased excess air levels necessary to maintain steam temperatures at low loads. This additional excess air provides sufficient oxygen for carbon burnout regardless of overfire air flow rate. However, at full load it appeared that increases in overfire air actually reduced CO emissions as shown in Figure 9. It is theorized that on a top-fired unit there is less forced mixing of the combustion products downstream of the burners. On wall-fired boilers the flame must turn and travel upward. This forces mixing of the combustion gases and allows for carbon burnout. On a top-fired boiler, forced mixing does not occur until the gases turn at the bottom of the boiler. The injection of overfire air adds turbulence and may reduce CO emissions.

Load Following NO_x Emissions

The NO_x reduction data previously presented in this paper were obtained at baseload conditions with testing personnel closely monitoring all boiler variables and represents the lowest NO_x emissions that can be obtained. Arapahoe 4 is generally operated as a load following unit under automatic control where oxygen levels can vary significantly and rapidly. This mode of operation tends to increase CO and NO_x emissions. Immediately following the parametric combustion testing, the unit was operated for two months under normal load following conditions. Figure 11 shows a comparison of the NO_x emissions of the DRB-XCL® burners with overfire air during baseload and load following operation. Depending on load, NO_x emissions are from 10 to 20% higher during load following operation.

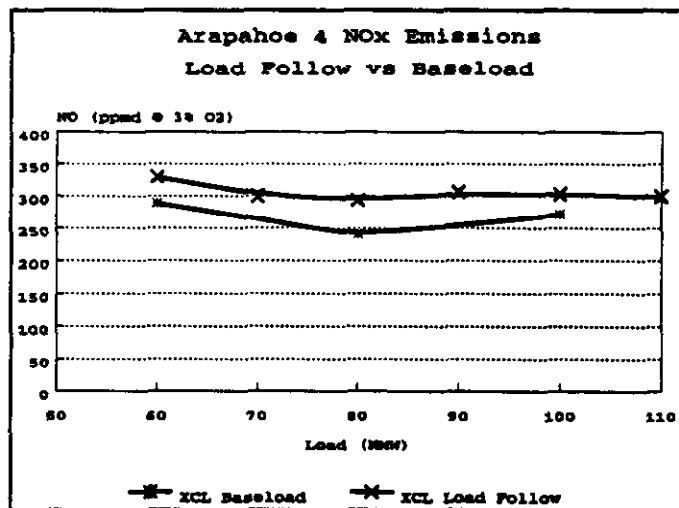


Figure 11 - Load Follow Operation

Selective Non-Catalytic Reduction Testing

Two phases of testing have been completed with the SNCR system. The system was originally tested with the high NO_x baseline that existed with the original burners. After the combustion system was retrofit, additional testing was completed with the reduced NO_x baseline.

Combustion System Effects

Figure 12 compares the NO_x removal and ammonia slip results at 100 MWe before and after the combustion modifications were completed. Note that with the original burners in-service and a NO_x baseline of 800 ppmc, approximately 35% NO_x reduction could be obtained with an ammonia slip of 10 ppm at the inlet of the fabric filter. After the combustion modification retrofit, the baseline NO_x was reduced to approximately 260 ppmc, and it was found that urea injection worked substantially better. NO_x reduction was increased to 42% while maintaining a 10 ppm ammonia slip. While this is not a large increase in NO_x removal, the significance is that the increased removal was obtained with a nearly 40% reduction in the amount of urea injected.

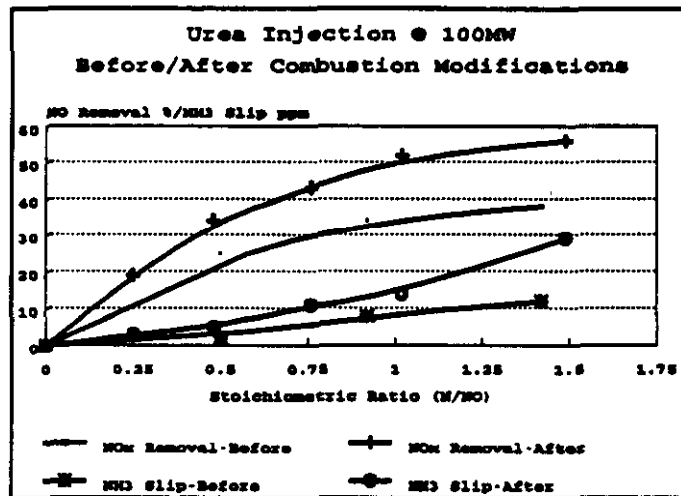


Figure 12 - Urea Injection 100MW

The data initially appear to show that SNCR is more effective at lower initial baseline NO_x levels. However, the combustion modifications did more than just reduce NO_x emissions. The modifications also reduced flue gas temperature in the area of urea injection by approximately 150°F across the load range. Urea injection is a very temperature sensitive process and minor temperature changes can significantly change both urea utilization and the maximum removal that can be achieved. It is currently believed that the primary reason for the increased urea utilization after the combustion retrofit is the decrease in flue gas temperature in the area of urea injection. With the original burners, the urea was being injected into a region that was too hot for efficient NO_x removal. At the lower temperatures that exist with the new burners, better NO_x reduction is obtained at equivalent urea flows but ammonia slip is increased. The net effect of the temperature change is higher NO_x reduction with lower chemical injection rates while maintaining comparable ammonia slip levels.

Load Variation

A series of parametric tests was completed over the normal load control range of Arapahoe Unit 4 of 60 to 110 MWe. The testing was conducted after the combustion modifications were complete with a NO_x baseline of approximately 260 ppmc while injecting urea. Figure 13 shows the NO_x removal and urea utilization with a constant 10 ppm ammonia slip at the fabric filter inlet. Utilization is used as a measure of the effectiveness of the urea and is defined as follows:

$$\text{Utilization} = \text{NO}_x \text{ Removal} / \text{Stoichiometry}$$

For the current injection system, it appears that the most efficient NO_x reduction occurs between boiler loads of 80 and 100 MWe. The flue gas temperature in the area of urea

injection at these loads is 1700 to 1800°F, which compares well with the expected optimum temperature for the process. As load is reduced to 60 MWe, the flue gas temperature cools and only 13% removal is possible at an acceptable ammonia slip. At the lower temperature, a significant amount of the urea converts to ammonia in a temperature range that is too cold to obtain NO_x removal. This increases ammonia slip and thus urea flow must be limited.

Ammonia/Urea Comparison

While urea injection allows reasonable levels of NO_x removal at higher loads, it was not very effective at low loads. In an effort to increase low load removal, the urea injection system was modified with an on-line ammonia conversion system. This system converts urea to liquid ammonia compounds immediately before injection into the boiler. As ammonia reacts faster than urea and in a lower temperature window, it was expected to provide higher NO_x removal at low load. Although various ammonia compounds have been tested at other sites, this is believed to be the first site where both chemicals have been used on the same full scale coal-fired utility boiler. Figure 14 shows the NO_x removal and utilization data obtained with ammonia verses urea injection. At all loads, ammonia injection provided slightly higher NO_x reductions at an equivalent ammonia slip. However, ammonia was generally much less efficient than urea, as shown by the lower utilization at loads above 70 MWe. At 60 MWe ammonia utilization is nearly 75% while urea utilization is reduced to only 45%, at injection rates limiting NH₃ slip to 10 ppm.

As load is reduced below 60 MWe, the temperatures at Arapahoe Unit 4 are too cold for efficient NO_x removal with either chemical. Although some NO_x removal is possible at 10 ppm slip, the small quantities are not economically productive. The automatic control system has been programmed to stop chemical injection at loads below 60 MWe. As Arapahoe 4 is usually operated under dispatch control in the range of 60 to 110 MWe, this will not be a major issue. If a significant period of operation is expected below 60 MWe, the unit is removed from dispatch control. At that same time the urea

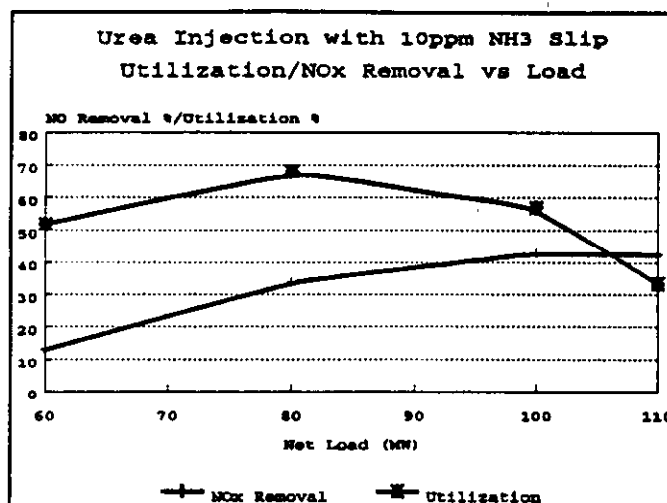


Figure 13 - Urea Injection NOx Rem.

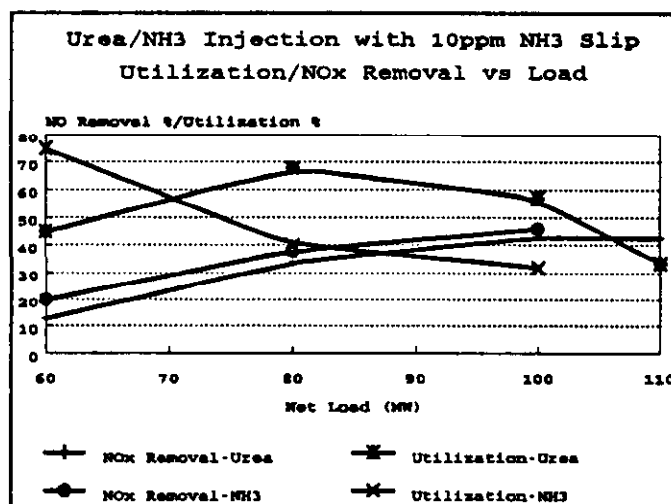


Figure 14 - Urea/NH3 NOx Rem

injection system will be shutdown and then restarted when load demand increases.

N₂O Generation

In addition to creating unwanted ammonia emissions, SNCR can increase nitrous oxide (N₂O) emissions. Figure 15 shows the increase in N₂O emissions as a percentage of the NO_x removed for three different loads. The N₂O generation at both 100 MWe and 80 MWe is very similar and is high at 25 to 30% of the total NO_x reduction. At reduced loads, i.e. lower flue gas temperature, N₂O was substantially reduced to under 20%. It appears that N₂O generation is related to temperature as is NO_x removal. At points where NO_x removal is very efficient, N₂O generation is high. At lower temperatures where urea utilization is reduced, N₂O generation is also reduced.

Figure 16 shows the N₂O generation while injecting ammonia at three different loads. While the trends are similar to those for urea, the levels of N₂O generated are substantially less with ammonia injection; less than 8% conversion. It should also be noted that the data shown in Figure 16 are for the converted urea. If conversion is not 100% to ammonia, then the N₂O levels would be expected to be somewhat higher compared to the injection of pure ammonia.

Dry Sorbent Injection Testing

Testing of the dry sorbent injection (DSI) system at Arapahoe 4 using calcium hydroxide has just recently been completed. Unfortunately, only minimal data is available at this time. Testing consisted of three phases, duct injection with humidification, economizer injection without humidification, and economizer injection with humidification. All testing to date has been with low sulfur coal with baseline SO₂ emissions in the range of 400 ppmc.

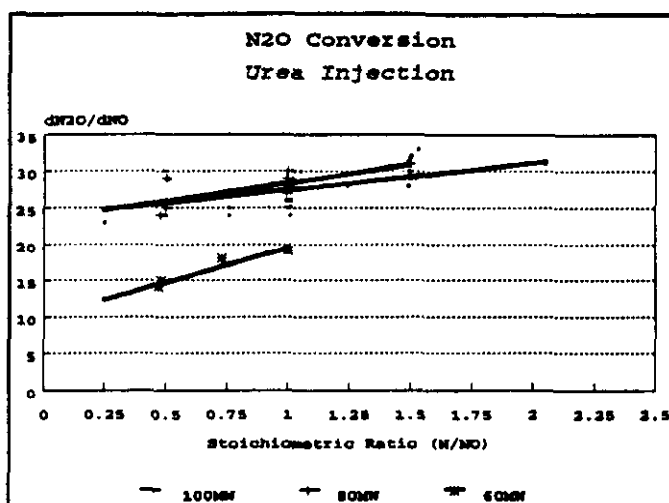


Figure 15 - Urea N₂O Generation

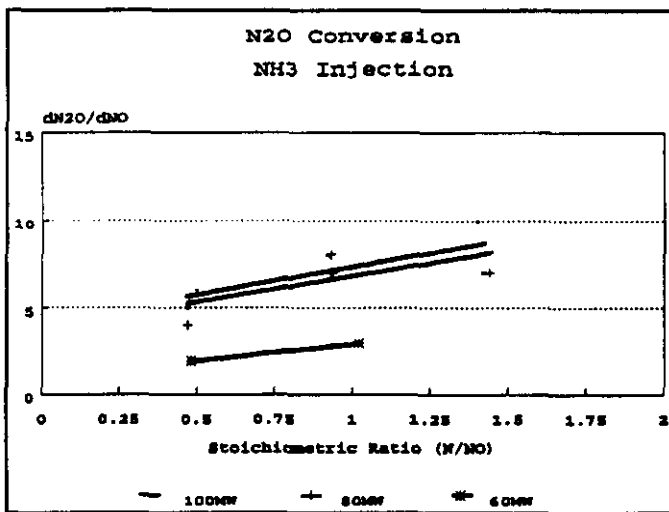


Figure 16 - NH₃ N₂O Generation

The most difficult testing task has been determining an accurate dry bulb temperature and the associated approach to saturation temperature ahead of the fabric filter. The original system consisted of a 12 point thermocouple grid 58 feet downstream of the humidification system. During initial operation it was found that the thermocouples within the grid were getting wet and thus the temperature obtained was not an accurate dry bulb temperature. A new 12 point thermocouple grid was installed at the entrance to the fabric filter 104 feet from the humidification system. The new temperature grid was more accurate than the original but at high loads generally under reported the dry bulb temperature. A portion of the thermocouples within the grid were then shielded to prevent direct water impact to the thermocouple. The inlet dry bulb temperatures now closely agree with the fabric filter outlet temperature and it is believed that an accurate approach to saturation temperature can be obtained.

The maximum SO₂ removal obtained has been in the range of 35 to 40%. This removal was obtained during a short term test with calcium hydroxide injected into the duct at a stoichiometric ratio of 2.0 and with the humidification system operating at a 20 to 25°F approach to saturation. Immediately after this test, problems developed with the flyash transport system and all bags in a small pulse jet filter were replaced. It is suspected that the low approach operation contributed to this problem although other possible causes for the replacement exist. It is currently believed that a 30°F approach temperature is more realistic and can be maintained for long periods without negative effects on the fabric filter. At this higher approach, SO₂ removal is reduced to a range of 25 to 30% at a stoichiometry of 2.0.

SO₂ removal has been substantially less than expected with calcium hydroxide injection at the economizer. Pilot scale testing in the range of 1000°F has shown the potential for SO₂ removals near 50%. At Arapahoe, initial testing at a stoichiometry of 2.0 without humidification resulted in SO₂ removals in the range of 5 to 8%. It was found that distribution of the sorbent with the original nozzles was very poor, and only approximately 1/3 of the flue gas was being treated. Although SO₂ removals of slightly above 30% were obtained in the area of treatment, the local stoichiometry in this area is estimated at 6.0. New nozzles that increase distribution to approximately 2/3 of the flue gas were installed on one-half of the boiler. With the improved distribution, SO₂ removal was increased to 10 to 12% at a stoichiometry of 2. Although distribution of the calcium reagent is not perfect, it appears that high levels of SO₂ removal are not possible at Arapahoe 4 using the current calcium hydroxide material; even in areas with high stoichiometries. Samples of the reagent have been analyzed for surface area and particle size; both parameters being important for economizer injection. The BET surface area of the Ca(OH)₂ is 14.8 m²/gm and the mass mean particle size diameter is 2.7 microns (determined by sedimentation). The relatively low surface area of the Ca(OH)₂ may be contributing to the low SO₂ removals obtained with economizer injection.

Operation of the humidification system during economizer injection increases SO₂ removal slightly. The economizer injection testing was completed before the addition of the thermocouple shields discussed above and the exact approach to saturation during this testing is unknown. At an estimated approach of 50°F, humidification increased the SO₂

removal of economizer calcium injection by approximately 4%. It is suspected that the calcium reagent has undergone chemical or available surface area changes that greatly decrease reactivity of the calcium hydroxide. Laboratory analysis of samples obtained upstream of the humidification grid are in progress to determine the reason for the low SO₂ removal efficiency during humidification.

CONCLUSIONS

Public Service Company of Colorado, in cooperation with the U.S. Department of Energy and the Electric Power Research Institute, has installed the Integrated Dry NO_x/SO₂ Emissions Control System. The system has been in operation for over a year and preliminary conclusions are as follows:

- NO_x reduction during baseload operation of the unit with the low-NO_x burners and overfire air ranges from 62 to 69% with no increase in unburned flyash carbon or CO emissions.
- Low-NO_x burners provided the majority of the NO_x reduction, while the overfire air system supplied approximately 8 to 20% additional NO_x reduction.
- NO_x emissions increased by up to 20% at Arapahoe 4 during normal load following operation when compared to baseload operation.
- Urea injection allows an additional 13 to 43% NO_x removal with an ammonia slip of 10 ppm at the fabric filter inlet. This increases total system NO_x reduction to nearly 80%, significantly exceeding the project goal of 70%.
- Higher NO_x reduction is possible using ammonia as the SNCR chemical, but significantly higher stoichiometric ratios are required at loads above 70 MWe.
- N₂O generation is a potential concern with urea injection but was greatly reduced when ammonia compounds were injected.
- SO₂ removals with the calcium-based dry sorbent injection have been less than expected with a maximum short term removal rate approaching 40%.

DISCLAIMER

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ACKNOWLEDGEMENTS

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**THE NOXSO COMBINED SO₂/NO_x REMOVAL FLUE GAS CLEANUP
SYSTEM COMMERCIAL DEMONSTRATION**

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ABSTRACT

The NOXSO process is a dry, post-combustion flue gas treatment technology which uses a regenerable sorbent to simultaneously adsorb sulfur dioxide (SO₂) and nitrogen oxides (NO_x) from the flue gas of a coal-fired utility boiler. The process does not produce any waste products. The SO₂ is converted to a saleable sulfur by-product and the NO_x is reduced to nitrogen and oxygen. The process is suited for either retrofit or new facility applications.

Testing was recently completed at the NOXSO pilot plant at Ohio Edison's Toronto Power Plant. Results showed that the process can economically remove more than 90% of the acid rain precursor gases. Removal efficiencies as high as 99+ % for SO₂ and 95% for NO_x were demonstrated during more than 6500 hours of testing.

The NOXSO Clean Coal Technology Project will demonstrate the NOXSO process on a commercial-scale. The \$66 million project is co-funded by the U.S. Department of Energy (DOE) under round III of the Clean Coal Technology program. The DOE manages the project through the Pittsburgh Energy Technology Center (PETC). The NOXSO process, pilot plant results, commercial-scale plant layout, and commercial-scale economics are described in this paper.

INTRODUCTION

The NOXSO process is a dry, post-combustion flue gas treatment technology which uses a regenerable sorbent to simultaneously adsorb sulfur dioxide (SO₂) and nitrogen oxides (NO_x) from the flue gas of a coal-fired utility boiler. In the process, the SO₂ is converted to a sulfur by-product (elemental sulfur, sulfuric acid, or liquid SO₂) and the NO_x is reduced to nitrogen and oxygen. Based on pilot plant results, the process can economically remove 90% of the acid rain precursor gases from the flue gas stream in a retrofit or new facility.

Process development began in 1979 starting with laboratory-scale tests and progressing to pre-pilot scale tests (3/4-MW) and a life cycle test. Each of these test programs [1,2,3] has provided data necessary for the process design. Tests of the NO_x recycle concept which, is inherent to the NOXSO process, have been conducted on small boilers at PETC and the Babcock & Wilcox (B&W) Research Center in Alliance, Ohio [4]. A 5 MW Proof-of-Concept (POC) pilot plant test at Ohio Edison's Toronto Plant in Toronto, Ohio was recently completed [5]. The Clean Coal Project is currently in the project definition phase incorporating recently obtained pilot plant data into a commercial-scale design.

The objective of the NOXSO Clean Coal Technology Project is to demonstrate the NOXSO process on a commercial-scale. At the completion of this project, economic and operating data will be available to assist utilities in making decisions regarding the choice of flue gas cleanup technology.

The project will be managed through the Pittsburgh Energy Technology Center (PETC) of the Department of Energy (DOE) through a Cooperative Agreement. The Cooperative Agreement is in the process of being assigned to NOXSO by Morrison Knudsen Corporation - MK-Ferguson Group (MK-Ferguson). With the reorganization of the project group, NOXSO will provide overall project management. MK-Ferguson will provide engineering and construction services and W.R. Grace & Co.-Conn. will be the sorbent supplier. NOXSO will conduct the operation phase of the project.

Funding for the \$66 million project will be provided by the DOE, the NOXSO development team, the Ohio Coal Development Office (OCDO), the Electric Power Research Institute (EPRI), and the Gas Research Institute (GRI).

NOXSO PROCESS DESCRIPTION

Flue gas is drawn from the power plant duct work either upstream or downstream of the particulate collection device by a flue gas booster fan. Figure 1 shows a process flow diagram with flue gas drawn from the particulate collection device discharge. Figure 1 shows single pieces of equipment, however multiples will be used as required to provide the necessary capacity. Tail gas from the sulfur by-product plant is mixed with the flue gas at the booster fan suction. The flue gas then passes through a two-stage, fluidized bed adsorber where SO_2 and NO_x are simultaneously removed using a high surface area γ -alumina sorbent impregnated with an alkali material. Water sprays into the fluid beds maintain a 250°F temperature by evaporative cooling. The cleaned flue gas passes through a particulate separator and is returned to the power plant chimney. Sorbent fines removed by the separator are directed to the dense phase transport system.

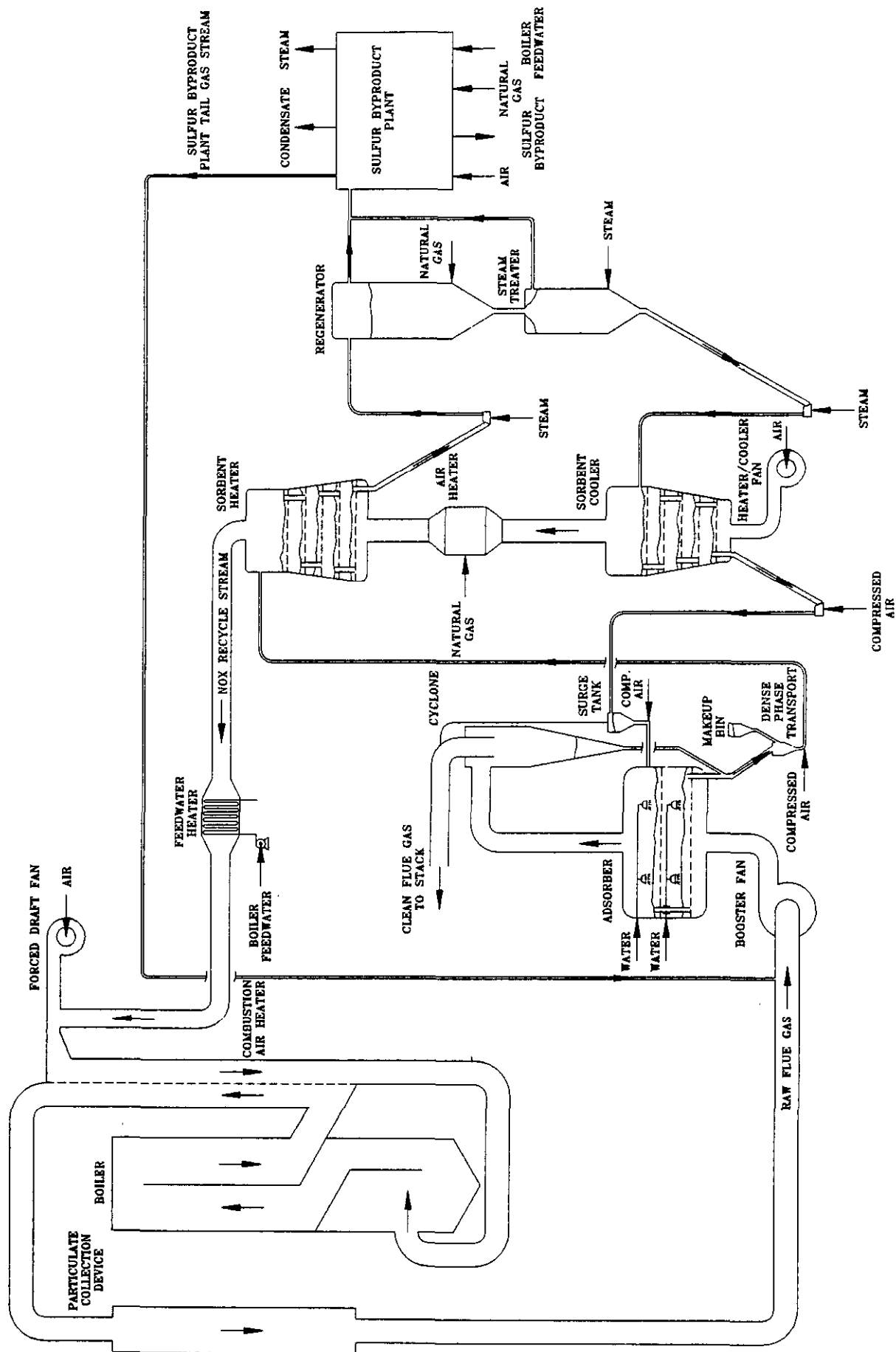


Figure 1. Process Flow Diagram

Sorbent from the adsorber is transported to the sorbent heater by a dense phase pneumatic conveying system. Make-up sorbent to maintain the sorbent inventory is added downstream of the adsorber. The sorbent heater is a variable area five-stage fluidized bed where a hot air stream is used to raise the sorbent temperature to 1150°F. During the heating process, NO_x and loosely bound SO₂ are desorbed and transported away in the heating gas (NO_x recycle) stream. This hot air stream at 500°F can be used to heat a slip stream of the power plant's main condensate before being injected into the combustion air system upstream of the combustion air preheater. The NO_x recycle stream provides approximately 30% of the required combustion air. Upon entering the boiler, a portion of the recycled NO_x is converted to nitrogen (N₂) reaction with free radicals in the reducing atmosphere of the combustion chamber.

Once the sorbent reaches a regeneration temperature of 1150°F, it is transported by means of a J-valve to the moving bed regenerator. In the regenerator, sorbent is contacted with natural gas in a countercurrent manner. The natural gas reduces sulfur compounds on the sorbent (mainly sodium sulfate) to primarily SO₂ and hydrogen sulfide (H₂S) with some carbonyl sulfide (COS) also formed. Some of the sodium sulfate (Na₂SO₄) is reduced to sodium sulfide (Na₂S) which is subsequently hydrolyzed in a moving bed steam treatment reactor which follows the regenerator. A concentrated stream of H₂S is obtained from the reaction of steam with Na₂S. The offgases from the regenerator and steam treater are combined and sent to a sulfur by-product plant which produces elemental sulfur, sulfuric acid, or liquid SO₂. The tail gas stream from the sulfur by-product plant is recycled to the suction of the flue gas booster fan.

From the steam treatment vessel, the sorbent is transported by means of a J-valve to the sorbent cooler. The cooler is a five-stage variable area fluidized bed which uses ambient air to cool the sorbent. The hot air exiting the cooler is further heated by a natural gas fired in-duct heater before being used to heat the sorbent in the fluidized bed sorbent heater. The sorbent temperature is reduced in the sorbent cooler to the adsorber temperature of 250°F. Sorbent from the sorbent cooler is transported by means of a J-valve to a surge tank¹ located above the adsorber. The surge tank is used as a source and sink for

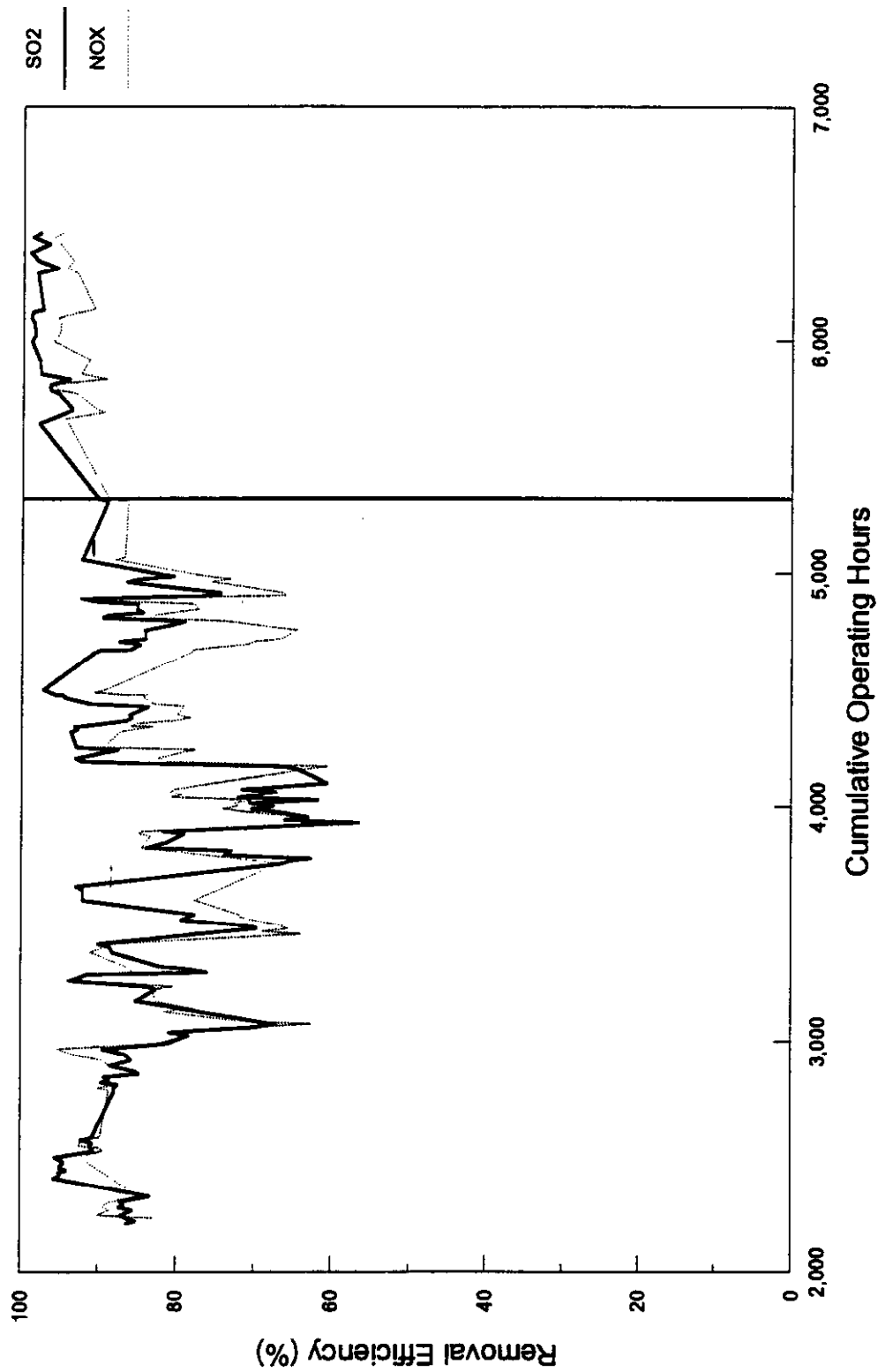
sorbent to maintain constant bed levels in the other process vessels. From the surge tank, sorbent flow to the adsorber is regulated using an L-valve, thus completing one full cycle.

PILOT PLANT SO₂/NO_x ADSORPTION RESULTS

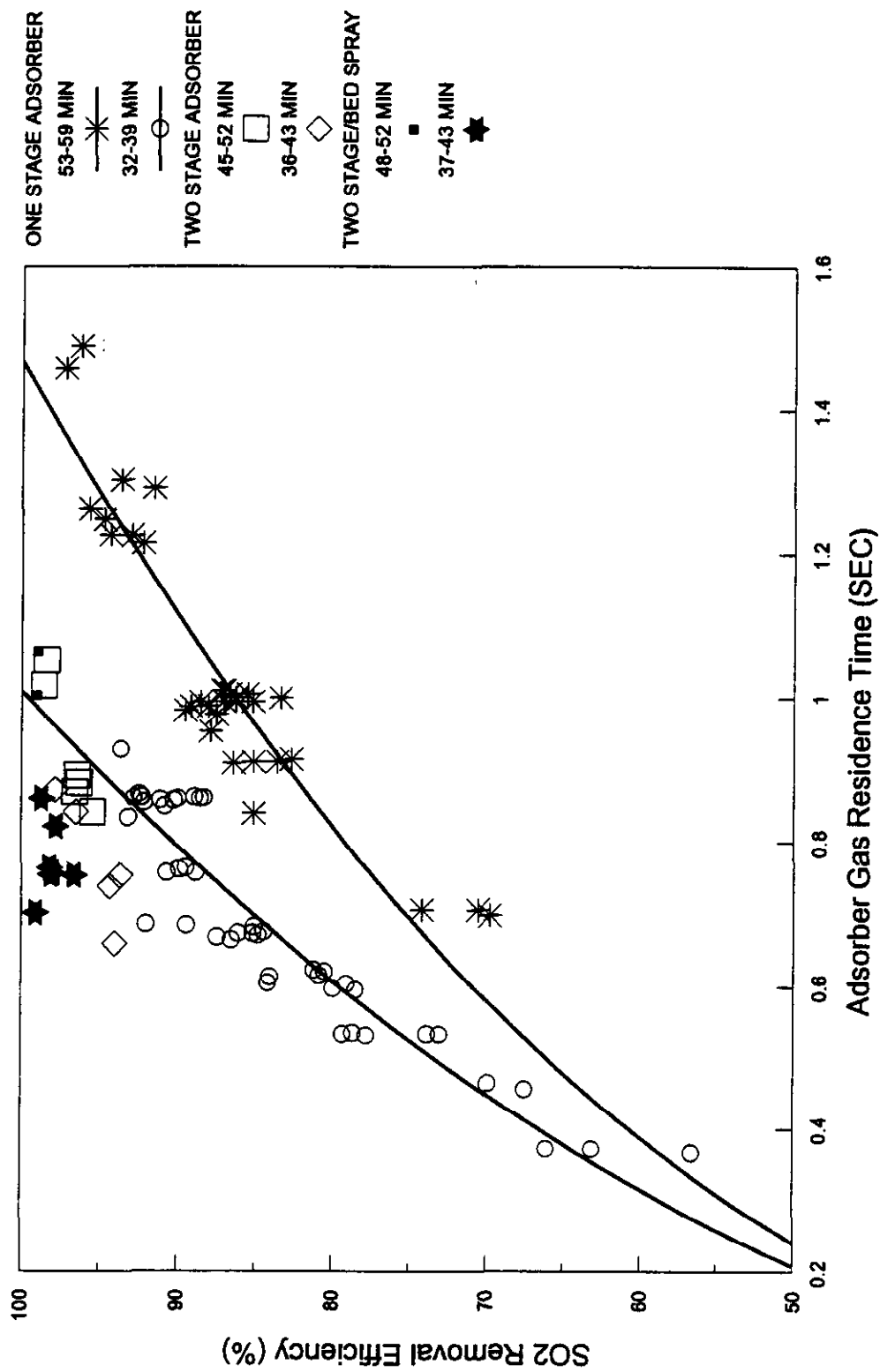
NOXSO operated a 5 MW pilot plant at Ohio Edison's Toronto Plant from September 1991 until August 1993. A major objective was to determine the effect of operating variables on the SO₂ and NO_x removal efficiency. Operating variables studied included sorbent circulation rate, gas residence time, solids residence time, number of adsorber grids, adsorber temperature, and pollutant concentration.

Figure 2 is a plot of SO₂/NO_x removal efficiencies versus cumulative plant operating hours. The data are averages computed over a minimum of four hours and a maximum of twelve hours. The data are selected from periods in which the plant sulfur and nitrogen oxides mass balance closures were $100 \pm 15\%$. The removal efficiencies in Figure 2 vary with time due to the fact that NOXSO process operating conditions were intentionally varied to quantify their effect on process performance. The process operating conditions varied and included flue gas flow rate, sorbent circulation rate, adsorber sorbent inventory, adsorber bed temperature, and adsorber inlet SO₂ and NO_x concentrations. Also tested were two different adsorber configurations: 1) a single-stage fluidized bed with flue gas cooling via water spray into the ductwork approximately 90 feet upstream of the adsorber, and 2) two fluidized beds in series with cooling via direct water spray into the beds. The vertical line in Figure 2 marks the time at which the second adsorber grid and in-bed water sprays were installed. Note that both SO₂ and NO_x removal efficiencies improved with the installation of the second grid.

Figure 3 is a plot of SO₂ removal efficiency versus adsorber gas residence time. When the data are segregated into groups with essentially the same sorbent residence time, an equation of the form, $y = ax^{1/N}$, $N > 1$, satisfactorily represents the data. This is true for the entire database of 117 data points, although for clarity only a portion of the database is



**Figure 2. NOXSO Pilot Plant
SO₂/NO_x Removal Efficiencies**



**Figure 3. SO₂ Removal VS Gas/Sorbent Residence Time
77 Data Points Used In Non-Linear Regression**

shown in Figure 3. The correlation coefficients (r^2) for the two curves shown in the figure are 0.85 (53-59 min) and 0.89 (32-39 min).

The strictly empirical correlation is best for intermediate values of SO₂ removal and short sorbent residence times when the relationship between SO₂ removal and gas residence time is nearly linear. The correlation is worst for high values of SO₂ removal and gas residence time, since the correlation gives no limiting value of removal efficiency, although the actual limit is 100%.

In addition to gas and sorbent residence time, SO₂ removal efficiency varies with the concentration of SO₂ in the flue gas inlet to the adsorber. Figure 4 shows that SO₂ removal efficiency is inversely proportional to the inlet SO₂ concentration. The proportionality constant (the slope of the lines in Figure 4) varies depending upon the ratio of flue gas flow to sorbent circulation rate.

Figure 3 also shows that the two-stage adsorber consistently out-performed the single-stage adsorber. This is seen more clearly in Figure 5 which shows the results of an identical series of tests on the one and the two-stage adsorber. For the one-stage adsorber, SO₂ removal efficiency is shown to be inversely proportional to the flue gas to sorbent mass ratio, all other operating variables are constant as noted at the bottom of the figure. When the tests were repeated with the two-stage adsorber, SO₂ removal efficiencies were higher by 5 to 10 absolute percentage points. This improvement is due to 1) better gas distribution with the addition of the second grid plate and 2) counter-current flow of gas and sorbent so that in the bottom bed of the adsorber partially sulfated sorbent is in contact with the highest concentration of pollutants providing the driving force to put more sulfur on the sorbent. All the data in Figure 5 were obtained at equal adsorber sorbent inventories, therefore the pressure drop across the two-stage adsorber is only greater than the one stage by the pressure drop across the second grid plate. (2-3" H₂O).

Figure 6 shows NO_x removal efficiency as a function of flue gas to sorbent mass ratio. As is the case with SO₂, NO_x removal efficiency decreases in proportion to the increase in mass

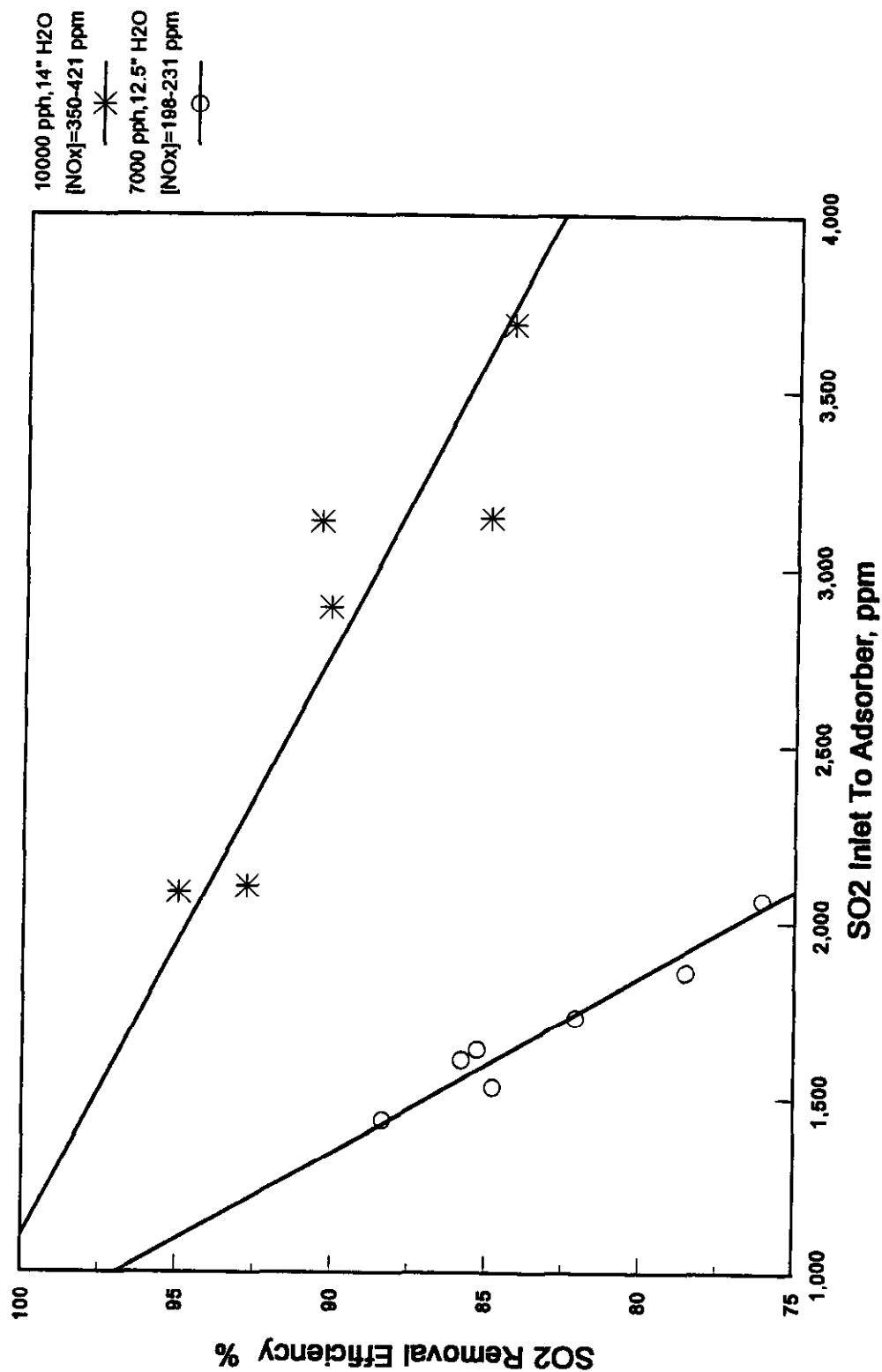


Figure 4. SO₂ Removal as a Function of Inlet SO₂
All Tests at 7000 scfm

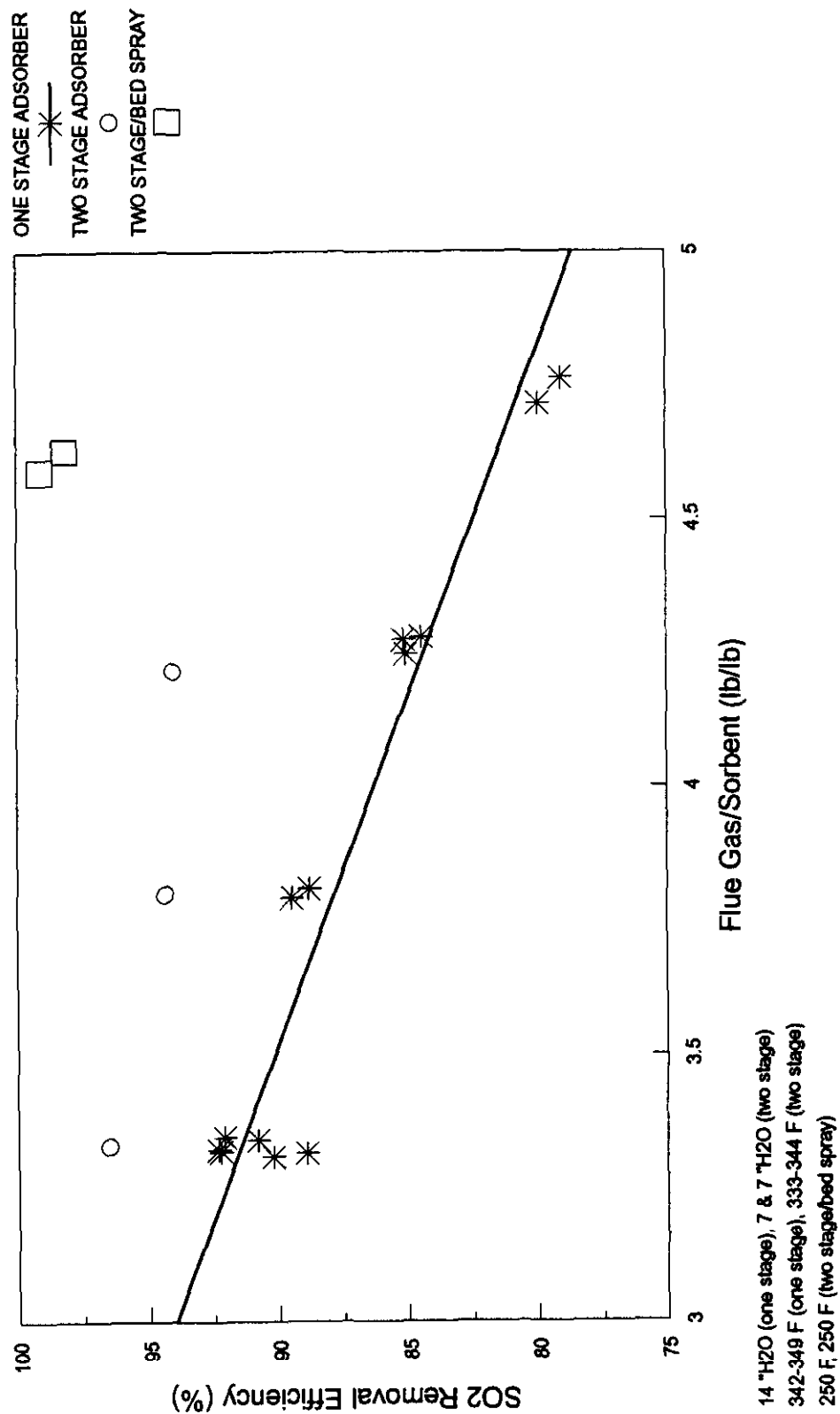


Figure 5. NOXSO Pilot Test
 SO₂ Removal Efficiency
 and Two-Stage Adsorbents

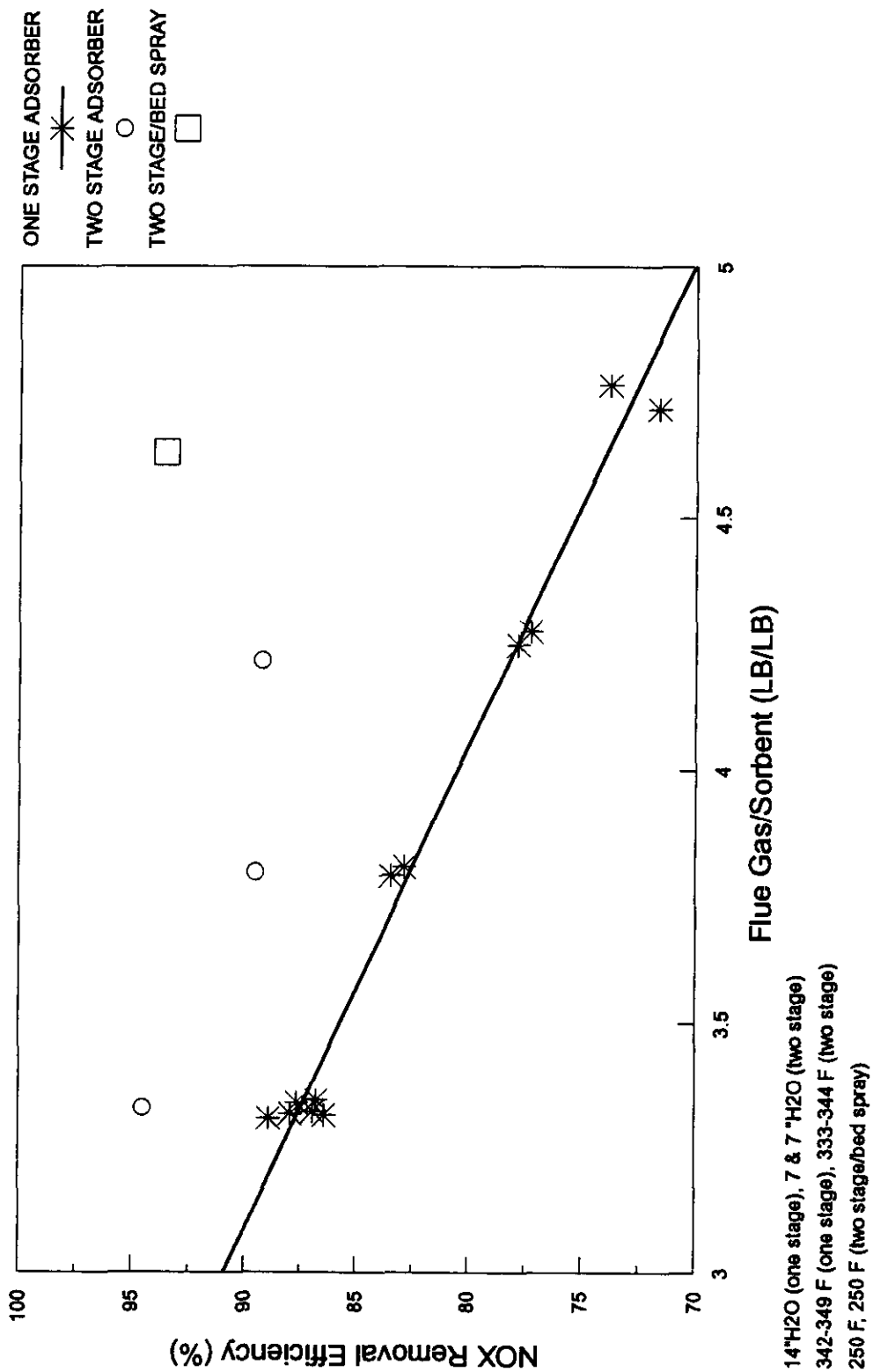


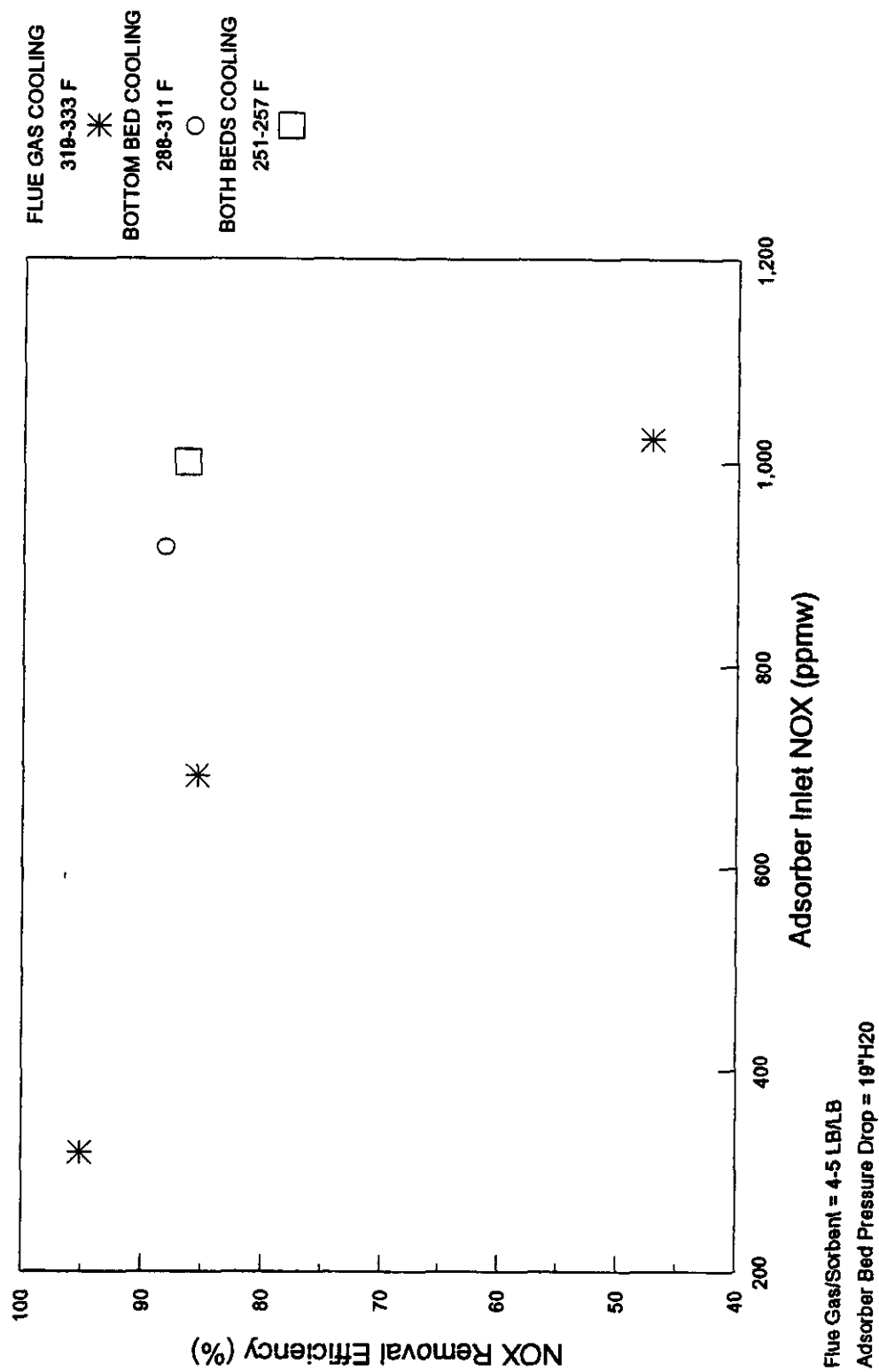
Figure 6. NOXSO Pilot Test
 NOx Removal Efficiency
 and Two-Stage Adsorbents

ratio, all other operating variables constant. The line drawn in the figure through the one-stage data has a correlation coefficient (r^2) of 0.98. The two-stage data show the same trend but removal efficiencies are 6 to 12 absolute percentage points higher than the one stage. The best line through the two-stage data extrapolates to 86% NO_x removal efficiency at a flue gas to sorbent mass ratio of 4.6. The two-stage/in-bed spray data point shown in Figure 6 is 93.5% NO_x removal at a mass ratio of 4.6. This shows the effect of adsorber bed temperature on NO_x removal. Data obtained over an adsorber bed temperature range of 250-356°F show a definite trend of increasing removal efficiency with decreasing bed temperature. Further improvement is probable at bed temperatures lower than 250°F. This trend was best illustrated in tests where the flue gas was spiked with SO_2 and NO_x from pressurized gas cylinders. Figure 7 shows NO_x removal efficiency as a function of inlet adsorber NO_x concentration from 300-1065 ppm. This is the range of NO_x concentration that exists in flue gas from coal-fired utility boilers. All tests were run at flue gas to sorbent mass ratios of 4.2 to 5 and total bed pressure drop of 19" H_2O in the two-stage adsorber. The data in Figure 7 clearly show that adsorber NO_x removal efficiencies of 86-88% are achievable at 917 to 1000 ppm inlet NO_x using the two-stage adsorber with in-bed water spray.

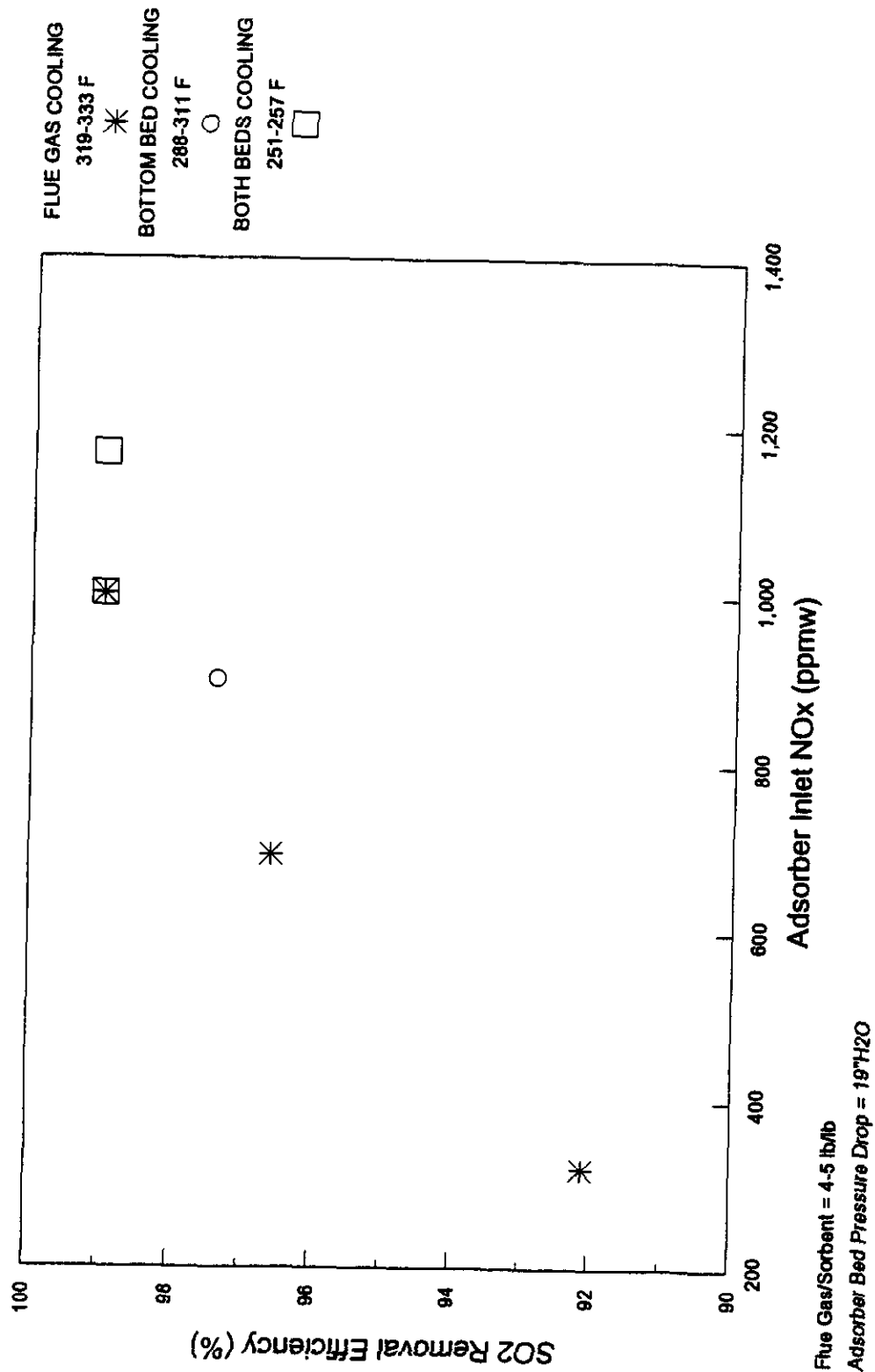
Figure 8 shows that SO_2 removal efficiency increases as the concentration of NO_x in the incoming flue gas goes up. This is because the SO_2 and NO_x adsorption mechanisms do not proceed independent of one another. In one-step in the mechanism, NO catalyses the reaction of O_2 and SO_2 on the sorbent's surface to form Na_2SO_4 , a stable compound.

SORBENT ATTRITION

Sorbent attrition is caused by physical and thermal stresses that come to bear on the sorbent as it is transported through the processing loop and as it resides in the fluid beds. These stresses can fracture sorbent beads and/or erode the surface of the beads. If the sorbent bead becomes small enough, it can be entrained by the gas and exit the fluid bed. Sorbent makeup is then required to maintain a constant sorbent inventory.



**Figure 7. NOXSO Pilot Test
Flue Gas Spiking with SO₂/NO_x
{SO₂}=2300-2600 ppm Two-Stage Adsorber**



**Figure 8. NOXSO Pilot Test
Flue Gas Spiking with SO₂/NO_x
[SO₂]=2300-2600 ppm Two-Stage Adsorber**

The rate of sorbent attrition equals the rate of sorbent makeup provided the starting and ending sorbent inventories are equal. The sorbent makeup rate at the NOXSO pilot plant for a 7-month period of operation is summarized in Table 1. The sorbent makeup rate is 3 PPH or $3/27,000 = 0.011\%$ of total sorbent inventory per hour. This equates to replacing the entire sorbent inventory approximately once a year. This makeup rate is slightly lower than the makeup rate (0.016%/hr) used in previously published estimates of NOXSO process operating costs.

Operation	
Start date	7/17/92
End date	2/11/93
Flue gas, hrs	3,232
Sorbent Inventory	
Total makeup, lbs	20,307
Sorbent lost, lbs	-6,415
Deduct sorbent inventory, lbs	-4,245
Net Sorbent Makeup, lbs	9,647
Sorbent Makeup Rate, lb/hr	3.00

Table 1. Sorbent Makeup Rate

GENERAL ARRANGEMENT

Figure 9 shows a general arrangement for a nominal 100 MW NOXSO plant. The major components will be identified by tracing the flow paths of the flue gas, the heater/cooler gas, and the sorbent through the system. This arrangement shows two adsorber trains. Flue gas enters the NOXSO system thru the flue gas inlet duct, splits and flows through the flue gas booster fans, adsorbers, and particulate separators before recombining and exiting the NOXSO tower thru the flue gas outlet duct.

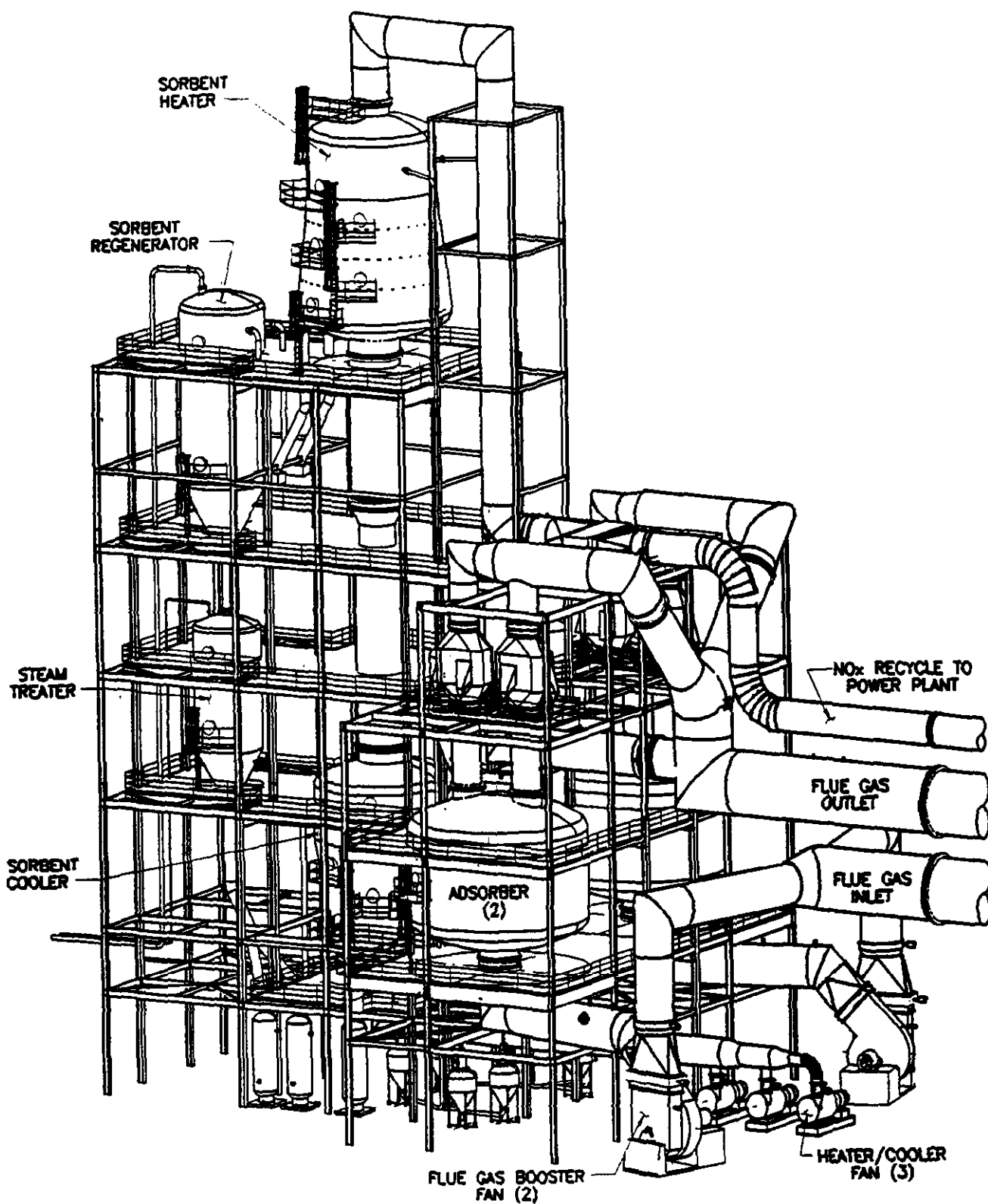


Figure 9. NOXSO Process Tower

Ambient air for cooling the sorbent enters through two of three 50% capacity heater/cooler fans. The air is preheated by the sorbent in the tapered sorbent cooler before flowing through the air heater (located below the sorbent heater) where it is heated by burning natural gas. The high temperature air enters the bottom of the tapered sorbent heater and exits from the top. This exit gas is the NO_x recycle stream which goes to the combustion air system of the power plant.

Sorbent is transported from the adsorbers to the sorbent heater. After being heated in the sorbent heater, the sorbent is transported to the moving bed sorbent regenerator and then to the steam treater. From the steam treater, the sorbent flows to the sorbent cooler where it is cooled before being transported back to the adsorber, completing the cycle.

PROJECT SCHEDULE

The Cooperative Agreement was awarded in March of 1991. The project has been in a project definition phase while the pilot plant has been operating. Current emphasis is on incorporating pilot plant results into a preliminary design for a commercial-scale plant and identifying a host site for the project. The project schedule by each phase is indicated in Table 2.

Preliminary Design	March 1991 - April 1994
Detail Design	May 1994 - October 1994
Construction	November 1994 - December 1995
Operation	January 1996 - December 1997

Table 2. Project Schedule

ECONOMICS

Data from the pilot plant have been incorporated into the design of a commercial-scale NOXSO plant. Using this commercial plant design, an economic analysis was performed.

The basis for the analysis and cost information are included in Table 3. The analysis was conducted for a 500 MW power plant burning 3% sulfur coal and emitting 0.6 lb NO_x/MMBtu.

Since the NOXSO process is a combined SO₂/NO_x removal process, it is not possible to separate the cost of removing SO₂ from the cost of removing NO_x. Consequently, an assumption is made that the cost of removing NO_x is 3.0 times higher than the cost of removing SO₂. The value of 3.0 represents a reasonable average for the relationship between the cost of NO_x and SO₂ removal based on published economic studies of separate high efficiency technologies. This value does not affect the overall economics, however it does affect the relative cost of SO₂ and NO_x removal.

Emissions data are also listed in Table 3. The "Phase I SO₂ Limit" is calculated based on allowable emissions of 2.5 lb SO₂/MMBtu. It is appropriate to consider over compliance since the high removal efficiency of the NOXSO process will allow a utility to generate SO₂ allowances which can be sold to partially offset the operating cost. A value of \$300 has been assumed for SO₂ allowances. Beginning in the year 2000, the number of allowances generated will decrease, however it is also likely that the value of allowances will be significantly higher offsetting to some degree the reduction in the number of allowances generated.

The annual operating and maintenance cost is \$24.7 million with the cost of sorbent at \$10.1 million representing 41% of the total. The capital cost of \$257/kw is based on a recent EPRI study [6].

Revenues for the process will be generated by the sale of the sulfur by-product and the SO₂ allowances. The sulfur by-product can be elemental sulfur, sulfuric acid, or liquid SO₂. The choice of sulfur by-product will be influenced significantly by the local demand for the specific product. Since the market for sulfur is larger than the other two, sulfur is used in this analysis. If a local market exists for sulfuric acid or liquid SO₂, either would be a more economical choice since the revenue from sulfuric acid would be approximately three times

Table 3. NOXSO PROCESS ECONOMIC ANALYSIS (1)

POWER PLANT PARAMETERS

GROSS CAPACITY	500 MW
CAPACITY FACTOR	70.0 %
HEAT RATE	10,000 Btu/kWh
COAL HEATING VALUE	12,000 Btu/lb
COAL SULFUR	3.0 %
NOx EMISSIONS	0.6 lb/MMBtu

ECONOMIC PARAMETERS

ELECTRICITY	\$0.03 /kWh
NATURAL GAS	\$2.50 /Mscf
SORBENT	\$3.40 /lb
NET SULFUR VALUE	\$50 /ton
SO2 ALLOWANCE VALUE	\$300
FIXED CHARGE RATE (2)	10.6 %
REMOVAL COST NOx/REMOVAL COST SO2	3.0

NOXSO PROCESS REMOVAL EFFICIENCIES

SO2	95 %
NOx	80 %

EMISSIONS DATA

UNCONTROLLED SO2	76,650 tons/year
CONTROLLED SO2	3,833 tons/year
PHASE I SO2 LIMIT	38,325 tons/year
SO2 ALLOWANCES GENERATED	34,493 tons/year
UNCONTROLLED NOx	9,198 tons/year
CONTROLLED NOx	1,840 tons/year
POLLUTANT REMOVAL EFFICIENCY	93.4 %

OPERATING AND MAINTENANCE COSTS

FIXED (3)	\$5,714,000
VARIABLE (4)	\$129,000
NATURAL GAS	\$5,131,000
SORBENT	\$10,112,000
ELECTRICITY	\$3,642,000
TOTAL	\$24,728,000

CAPITAL COST

\$128,500,000
\$257 /kW

REVENUES

SO2 ALLOWANCES	\$10,347,750
SULFUR VALUE	\$1,820,438
TOTAL	\$12,168,188

NET LEVELIZED COST

\$26,180,813 /year
8.5 mills/kWh
\$276 /ton-SO2
\$828 /ton-NOx

(1) 1993 dollars.

(2) Based on 30 year book life, 20 year tax life, 38% composite federal and state tax, and 2.0% for property taxes and insurance.

(3) Includes operating labor , fringes, and supervision; maintenance labor and equipment; and general and administrative expenses.

(4) Includes process water and Claus plant catalyst.

more than sulfur and liquid SO₂ would be six to eight times more. Making sulfuric acid or liquid SO₂ would also result in minor increases in capital and operating costs.

The net levelized cost for the process is presented from three points of view. The cost of buying, operating, and maintaining the plant will be \$26.2 million dollars per year. This translates to 8.5 mills/kwh of electricity produced. On a pollutant removal basis, it cost \$276 to remove each ton of SO₂ and \$828 to remove each ton of NO_x.

ACKNOWLEDGEMENT

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THE MILLIKEN STATION CLEAN COAL DEMONSTRATION PROJECT: THERE'S MORE TO IT THAN CONCRETE AND STEEL

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INTRODUCTION

Three years after its conception, the Milliken Station Clean Coal Demonstration Project in the Town of Lansing, north of Ithaca, New York, is reality.

A network of gray steel I-beams, the superstructure of the flue gas desulfurization building, dissects the view of Cayuga Lake from the hillside above the plant. That steel and the flurry of construction activity at Milliken Station somehow make March 1995 -- the target for the wet limestone scrubber to begin removing up to 98 percent of Milliken's sulfur dioxide emissions -- seem much closer than it did even a few months ago.

The goals of the project are to:

- Reduce SO₂ emissions by up to 98 percent using Saarberg-Hölter Umwelttechnik's (Saarbrücken, Germany) formic-acid enhanced scrubbing process in a split-module absorber. The absorber will be lined with ceramic tile manufactured by Stebbins Engineering & Manufacturing Company (Watertown, New York).
- Reduce nitrogen oxides (NO_x) emissions by installing low-NO_x burners in Milliken's two tangentially-fired boilers and by demonstrating Nalco Fuel Tech's (Naperville, Illinois) urea injection NO_xOUT® process on one boiler.
- Minimize solid waste production by making high quality, commercial grade gypsum, marketable mixed chloride salts.
- Maintaining fly ash quality to ensure continued sales.
- Demonstrate zero wastewater discharge.
- Minimize the scrubber's impact on Milliken's thermal efficiency primarily by installing a high efficiency air heater system manufactured by ABB Air Preheater (Wellsville, New York). (Milliken Station is consistently among the top 20 fossil fuel-fired generating station's in the U.S. in heat rate).
- Achieve 95 percent scrubber availability.

PROJECT STATUS

Several major milestones have been reached since the last Clean Coal Technology Conference in September 1992:

- Secured all permits to construct and operate the scrubber on or before September 1, 1992.
- Executed a cooperative agreement and repayment plan with the U.S. Department of Energy on October 22, 1992.
- Started construction of the scrubber in April 1993; completed foundations for the scrubber and the flue gas desulfurization building on June 18; started erecting steel in June 1993.
- Completed Unit 1 outage, which included installation of low-NO_x burners and new coal mills, on July 17, 1993.

- Received Finding of No Significant Impact from DOE on August 23, 1993.
- Constructed and began operating three ambient air quality monitoring stations and a central meteorological station in February 1993. Data will be collected through the end of the project's three-year demonstration period.

COMMUNICATIONS AND OUTREACH ACTIVITIES

In many respects, the Milliken Clean Coal Demonstration Project began like any other construction project. Management put together a project team of engineers, contract administrators, environmental specialists and number crunchers to get the project done "on time and under budget." Fortunately, before NYSEG applied to the U.S. Department of Energy for funding from the Clean Coal Technology Program - Round IV, the Milliken project team realized that an important element was missing from the process, a communications function to open and maintain communications channels with external and internal stakeholders. *

In another place and another time, employees were accepting of everything management prescribed and the public was docile and unwilling to question.

Today, employees insist on being involved and informed and the public is no longer at all hesitant to ask the tough questions and to stand up for what they believe is right.

The Milliken project team recognized the potential public concerns regarding the project, especially the visual impact of the new facilities, the year-round white plume

- * A stakeholder is any person, group or organization that is affected by NYSEG's actions and/or depends on NYSEG for the realization of their goals.

from the new stack, and the impact of a significant increase in truck traffic on two-lane state highways. The project team was especially sensitive to these issues because Milliken Station is located on Cayuga Lake, the second largest of New York State's scenic Finger Lakes. The residents of this region are particularly tuned-in to environmental issues and sensitive to changes that would impact the landscape. The team also recognized that it was important for the public to understand the positive impacts the project would have -- especially the environmental and economic benefits.

The Milliken project team identified a sub-team to address project communications needs. The following have been active members of the project communications team:

- Project manager
- Milliken Station manager
- Ithaca Division manager
- Media specialist
- Project environmental and public information specialist
- Manager - environmental issues
- Representative from ENSR Consulting and Engineering

Identifying Communications Objectives

The project communications team's first task was to identify communications objectives. They are to:

- Open channels of communications with internal and external stakeholders early in the project planning process and maintain those open channels (As Ann Carney and Amy Jordan note in a recent article in Public Relations Journal: "It is human nature for people to gossip. What they don't know they will fabricate or what little they do know they will embellish...To avoid this, a company must communicate quickly, honestly and frequently with its various audiences. It is not a matter of how much the company communicates, as much as it is that the lines of communications are open." [1])
- Provide timely, accurate and understandable information to internal and external audiences
- Anticipate and diffuse any negative community reaction

- Serve as the most accurate and reliable source of information for the neighbors of Milliken Station, public officials, the media and the general public
- Provide opportunities for public participation throughout the planning, construction and operation phases of the project

The project communications team recognized that achieving these objectives was essential to the success of the project. As Fraser Seitel, a veteran communicator who spent 20 years at Chase Manhattan, states in his book, The Practice of Public Relations: "...a thoughtful public relations program can crystalize attitudes, reinforce beliefs, and occasionally change public opinion." [2]

Perhaps most visibly at the Seabrook and Shoreham nuclear generating stations, it has become apparent that the public, agitated and angry because it has been left out of the communications loop, can cause havoc. According to Seitel: "Intelligent organizations in our society must be responsive to the needs and desires of their communities. Positive community relations in the '90s must begin with a clear understanding of community concerns, an open door for community leaders, and an open and honest flow of information from the organization, and an ongoing sense of continuous involvement and interaction with community publics." [3]

The team then recognized that achieving these objectives need not involve mentally-exhausting planning sessions, complicated communications plans and convoluted messages. Rather, the team again sided with Seitel: "There is really no trick to effective communication. Other than some facility with techniques, hard work and common sense are the basic guiding principles. Naturally, communication must follow performance; organizations must back up what they say with action. Slick brochures, engaging speeches, intelligent articles, and a good press may capture the public's attention, but in the final analysis the only way to obtain continued public support is through proper performance." [4]

The team, working within the constraint that no one had been assigned full-time communications responsibilities for the project, also recognized that it would take several individuals with specific skills and responsibilities to pull together the communications effort. These individuals were forced into performing as a team, just as the corporation was beginning to instill in its employees the virtues of teamwork. The circumstances dictated that this would be a true test of what Jon Katzenbach and Douglas Smith extol in their book, The Wisdom of Teams: "We believe that teams -- real teams, not just groups that management calls "teams" -- should be the basic unit of performance for most organizations, regardless of size. In any situation requiring the real-time combination of multiple skills, experiences, and judgments, a team invariably gets better results than a collection of individuals operating within confined job roles and responsibilities." [5]

Finally, each member of the team recognized that in addition to their full-time project responsibilities they would each be acting in a dual communications role. As Seitel notes: "Public relations practitioners are basically interpreters. On one hand, they must interpret the philosophies, policies, programs, and practices of their management to the public; on the other hand, they must translate the attitudes of the public to their management." [6]

Identifying Stakeholders

The following stakeholders were identified. This list was shortened to a list of key stakeholders to make the communications effort more manageable and maximize the opportunity to achieve the project communications objectives. The key stakeholders received most of the attention from the project communications team, but the remaining stakeholders were certainly not ignored. (The key stakeholders are noted with asterisks.)

- Neighbors of Milliken Station *
- Other residents on the east and west sides of Cayuga Lake *
- Town of Lansing officials (host community) *
- Tompkins County Environmental Management Council *
- Local media *

- Regional media
- National media
- State elected officials who represent the project area
- State agency officials
- Federal elected officials who represent the project area
- Federal agency officials
- Project co-funders (See addendum)
- Project participants (See addendum)
- Project consultants (See addendum)
- NYSEG employees
- NYSEG customers
- NYSEG shareholders

Stakeholder Analysis

Once the key stakeholders had been identified, the project communications team completed a stakeholder analysis during which it identified:

- Any individuals, groups or organizations which represented those key stakeholders or groups (for example, the neighbors of Milliken Station are represented by the Town of Lansing officials, the Tompkins County Environmental Management Council, other elected and agency officials, and even the media)
- Any individuals, groups or organizations which the key stakeholders represent (for example, the neighbors of Milliken Station also represent the interests of residents who live on both sides of Cayuga Lake)
- Issues or concerns of the key stakeholders (for example, the neighbors of Milliken Station might be concerned with increased traffic and noise both during construction and after the scrubber begins operating)
- Strategies to resolve the key stakeholder's issue or concern (for example, certain construction activities were limited to specific hours, noise abatement was investigated, and ways to control traffic once the scrubber begins operating were studied)
- Actions required (for example, contract terms were written to limit construction activities, a noise abatement consultant was hired, and a new entrance road to Milliken was constructed to improve traffic flow)

The stakeholder analysis provided the project communications team with a clear picture of interrelationships between key stakeholders and a reasonable idea of what needed to be planned into the project to address the concerns of key stakeholders. In addition, the analysis provided the project communications team with direction to develop the following communications tools:

- Project presentation with slides
- Newsletter for neighbors
- Project fact sheet

Key members of the project communications team were also trained in how to deal with the public and the media.

To open channels of communications with key stakeholders, the project communications team scheduled and carried out the following activities:

- Public information meetings in the cities of Ithaca and Auburn and the towns of Lansing, King Ferry and Trumansburg (These meetings, which were initiated by NYSEG prior to permitting activities, included a brief presentation on the project, highlighted the project benefits and trade-offs, and provided all interested parties with an opportunity to ask questions. In addition, the meetings provided an opportunity for the project communications team to confirm the results of their stakeholder analysis and gather suggestions from stakeholders for investigation.)
- Meetings with elected officials in the towns of Lansing and Genoa (These meetings provided elected officials with basic project information and personal contacts to foster rumor control.)
- Meeting with the Tompkins County Environmental Management Council (This meeting allowed the project communications team to understand the Council's concerns so they could be addressed during project design.)
- Media tour of Milliken Station (The tour provided the local media with basic project information and a walk-through. None of the five reporters in attendance had ever been in a generating station.)

- Meetings with a variety of service clubs and other organizations (The project communications team made it known that it would meet with anyone, at any place and any time to discuss the project. This offer generated many requests, all of which were honored.)
- Production of a public information videotape.
- Hand delivery of information to the neighbors of Milliken Station regarding unusual construction activities, such as blasting, and changing traffic patterns.

In each of these instances, all interested parties were given the opportunity to be added to a mailing list to receive News for Neighbors, a periodic newsletter on the project, and other project information.

RESULTS

As Seitel notes in The Practice of Public Relations: "Public opinion is a lot easier to measure than it is to influence." [7] We, however, do believe very strongly that we have influenced public opinion regarding the Milliken Clean Coal Demonstration Project by opening communications channels very early in the project, providing a comprehensive overview of the project, answering questions openly and honestly, respecting people's opinions and considering their suggestions. As we near the half-way point in construction of the scrubber, public support of the project has never been stronger and the organizations participating in the project have never been more supportive.

The most recent evidence of this broad support came on August 23 when representatives of NYSEG, all project co-funders, participants and consultants, the New York State Department of Environmental Conservation, the New York State Public Service Commission, the Adirondack Council, and local, state and federal elected officials gathered at Milliken Station to recognize progress to-date and pledge support for the future.

We are now broadening the communications objectives to accommodate:

- Verification to stakeholders that we have kept our promises
- Communications needs of project participants
- Discussion of the environmental monitoring plan
- Discussion of demonstration results

Communications efforts continue as we strive to cement support for the Milliken project during construction and the three-year test period.

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ADDENDUM

PROJECT CO-FUNDERS

New York State Electric & Gas Corporation Binghamton, New York	\$97 million
U.S. Department of Energy Clean Coal Technology Program - Round IV	\$45 million
Electric Power Research Institute Palo Alto, California	\$7 million
Empire State Electric Energy Research Corporation New York, New York	\$7 million
CONSOL, Inc. Library, Pennsylvania	\$2 million
New York State Energy Research and Development Authority Albany, New York	\$1 million

PROJECT PARTICIPANTS

Saarberg-Hölter Umwelttechnik Saarbrücken, Germany	Scrubber technology
Stebbins Engineering & Manufacturing Company Watertown, New York	Tile lining for scrubber
Nalco Fuel Tech Naperville, Illinois	NO _x control technology
ABB Air Preheater Wellsville, New York	Air heater system

PROJECT CONSULTANTS

Gilbert/Commonwealth Reading, Pennsylvania	Engineering, construction management
ENSR Consulting and Engineering Acton, Massachusetts	Environmental consultant, air quality
Galson Corporation Raleigh, North Carolina	Air impact modeling
Acentech Cambridge, Massachusetts	Noise abatement consultant

Luncheon

Speaker introduced by:

C. Lowell Miller,

Associate Deputy Assistant Secretary for
Clean Coal Technology,
U.S. Department of Energy

WHAT CLEAN COAL BRINGS TO THE INTERNATIONAL MARKET

**David C. Crikelair
Vice President
Texaco, Inc.**

**(The comments of Mr. Crikelair were not
available at the time of publication.)**

Plenary Session 2

Emerging Issues/Environmental

Moderator:

C. Lowell Miller,

Associate Deputy Assistant Secretary for
Clean Coal Technology,
U.S. Department of Energy

COMPLIANCE STRATEGIES - IMPACT ON CLEAN COAL DEPLOYMENT

**Stephen D. Jenkins
Manager, Advanced Technology
TECO Power Services Corporation**

**(The comments of Mr. Jenkins were not
available at the time of publication.)**



**DEFINING UTILITY TRACE SUBSTANCE
EMISSIONS AND RISKS**

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Second Annual Clean Coal Technology Conference

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DEFINING UTILITY TRACE SUBSTANCE EMISSIONS AND RISKS

Ian M. Torrens

I. INTRODUCTION

The purpose of this paper is to provide an update on the activities of EPRI and other organizations, including DOE, aimed at improving the quality of available information on utility trace element emissions, control technologies and risks. Thanks to these efforts, the state of knowledge is advancing rapidly. The rapid pace of progress was most evident at the recent Second International Conference on Managing Hazardous Air Pollutants, held in Washington DC this July. However, as in many fields of investigation, new information can sometimes raise more questions than it answers!

The 1990 Clean Air Act Amendments aim to reduce emissions of 189 substances that they designate as hazardous air pollutants - commonly called air toxics. The more neutral term "trace substances" is used in this paper, since most are emitted in extremely low concentrations from utility stacks. The degree of toxicity or hazard at these concentrations is subject to considerable uncertainty, and clarifying this is one of the objectives of the work in progress. A 1989 EPA-sponsored report concluded that emissions of potential cancer-causing substance from electric utility boilers pose insignificant risks -- less than 1 excess cancer per year in a population of over 200 million [1]. Nonetheless, how to manage these substances may be a new challenge for the electric power industry.

The most clear and urgent need emanating from the CAAA has been to obtain reliable information on which of the substances on the CAAA list are emitted from different types of power plants - in what amounts, what risks they pose, how much is removed by today's pollution control equipment, and how these substances will affect health risk for the industry after the year 2010? We also need to know how and at what cost they may be controlled if some significant risk is found leading to their regulation .

EPRI is addressing the issue on several fronts:

- developing a data base and tools that will enable utilities to estimate emissions levels from their power facilities, given the types of fuels burned and plant characteristics;
- developing a better understanding of how emissions are transported and transformed before they encounter humans and ecological systems;
- and assessing the risk to public health and the environment posed by utility releases of these substances.

II. THE EPRI PISCES PROJECT

To help the electric utility industry better understand emissions of potentially toxic chemicals from fossil fuel power plants, EPRI initiated the PISCES (Power Plant Integrated Systems: Chemical Emissions Study) project in mid-1988. The project involves the collection and review of data regarding the source, distribution, and fate of chemicals in both conventional and advanced fossil-fuel fired power systems.

The PISCES project has built a database from published information, and constructed a predictive computer model for power plant emissions. PISCES is multi-media in perspective; that is, it evaluates the presence and fate of chemicals in water and solid waste discharges, as well as in air emissions. This approach is being taken so that the effects of controls on air emissions, for example, can be assessed with full knowledge of the impacts on other plant process streams -- a way of integrating the array of pollution mitigating strategies.

The project consists of several major products and activities (Figure 1) including:

- a database of information gathered from the literature and other sources;
- an interactive power plant computer model to track the pathways of chemical substances and predict trace substance emissions;
- a field measurement program to measure emissions of two dozen chemicals in utility flue gas at plants and pilot test facilities employing a variety of emission control technologies. The results are being incorporated into the database and computer model;
- a series of emission control technology engineering reference guidelines to be developed following the completion of the database with new field measurements;
- measurement methods validation and a set of guidelines for measuring trace chemicals in utility process and discharge streams;

1. PISCES Data Base and Model

A great deal of information, both domestic and international, was available at the time PISCES was initiated, but there had been little uniformity in either measurement or estimation methodologies [2,3]. Early phases of the PISCES project focused on available literature information collection for conventional coal-, oil-, and gas-fired power plants. Over 500 chemicals have been identified in power plant process streams. Approximately 80 of these 500 were selected for additional data search on regulatory limits and health effects. The PISCES database currently contains more than 150 megabytes of literature information, including 80,000 records of reported quantity data. Detailed descriptions of the database have been reported elsewhere [4].

Given sufficient data in the PISCES database, first order predictions of air quality control technology performance for air toxics removals could reasonably be attained. However, the major issue is the lack of fundamental data about these technologies for chemical species of concern. Although the number of available data points for plant emissions of various chemical species is quite large, the number of paired data sets – inlet and outlet – on any given control device is sparse. This led to initiating EPRI's Field Chemical Emission Measurement (FCEM) program in association with EPRI member companies and the U.S. DOE.

1. PISCES Field Chemical Emissions Measurement

The PISCES FCEM program began in May 1990. Emissions and discharges are being measured for several control technologies, including cold-side ESPs, fabric filters (conventional and pulse-jet), low-NO_x burners, postcombustion NO_x systems, spray dry FGD, and wet lime/limestone FGD. Plant mass balances are being performed for some 24 chemicals to define sources, pathways, and the way they partition in the plant system.

Table 1 shows the substances being measured. Liquid and solid waste streams are sampled in addition to the flue gas. A variety of fuel types, combustion systems and types of environmental control for particulates, SO₂ and NO_x are included in the program. Early measurements pointed up the need for better sampling and analysis techniques for some of the trace chemicals, and as these have improved, so has the quality of the data (see Section II.7). Until the current series of tests has been completed and the entire body of information analyzed later this year and early next, the data should be considered preliminary.

Sampled early in the program was a midwestern U.S. power plant equipped with an ESP and wet limestone scrubber burning a western subbituminous coal. The FGD system at the time was operating with 24% flue gas bypass. The data indicate that, with the exception of mercury and chloride, over 90% of each chemical was removed with most showing over 95% removal (Figure 2). Mercury removal has been difficult to accurately determine since it is present in such low concentrations in the clean flue gas (less than 0.2 micrograms/Nm³).

Comparing the PISCES FCEM test results to information in the literature database, one can reaffirm our common understanding of the fate of certain classes of chemical species within the power plant. For example, comparing the concentration of chromium in coal with that found in the fly ash indicates that a large proportion of chromium is captured with the particulate matter (Figure 3). This would suggest that highly efficient particulate control devices, such as electrostatic precipitators (ESPs) and baghouses, would remove chromium and other similarly behaving elements from power plant flue gas streams quite efficiently. In fact, EPRI field studies have shown that chromium concentrations in the stack are quite low.

Electrostatic Precipitator (ESP) - controlled coal-fired power plants represent the largest segment of the industry tested under EPRI's PISCES and DOE's air toxics field sampling programs. Early test results have demonstrated the tremendous capacity of particulate collection devices to reduce many heavy metals from flue gas streams. A number of metals such as arsenic, nickel, chromium, lead, cadmium can be removed by an average of better than 90%. Figure 4 illustrates this point for arsenic and chromium. With very limited results (4 early sites), the removal performance from fabric filters are quite encouraging, indicating reductions over 99% for metals such as arsenic.

Much of the reductions are attributable to the metals condensation onto particulate material as combustion gas temperatures drop from 1260°C (2300°F) in the boilers to 121°C-149°C (250°F-300°F) inlet to the cold-side particulate capture devices. This suggests that conditions which promote lower temperatures and improved removals of combustion and post-combustion particulates and aerosols would also serve to control many of the heavy metals. [Future test data will be carefully examined to confirm these hypotheses.] The exceptions to this may be the more volatile elements such as mercury and selenium.

Material balance for variety of key elements has been excellent (Figure 5). Many are within or close to the 70% to 130% desirable interval. 100% closure represents a complete material balance. Of the key elements, selenium's balance appears consistently to be the most variable. The large uncertainties for selenium measurements in the flue gas may be attributable to interferences in the measurement methodologies, warranting further investigation.

3. Mercury

Mercury has been singled out for special study in the CAAA because of issues related to mercury from all sources, and human health (Figure 6). Mercury removal is difficult to determine accurately since the mercury is present in such low concentrations in the stack flue gas in the order of 0.0001 to 0.001 mg/Nm³). Uncontrolled emissions of a typical 500MW power plant would be about 500 pounds/year. Actual emissions in practice would be less since the plants environmental control systems actually do remove some mercury. Utility emissions of mercury are relatively small; that is, the annual contribution from U.S. fossil-fuel fired electric utility boilers represents roughly 2 percent of the 6 million kilograms global mercury budget and less than 4 percent of global anthropogenic emissions [5,6].

Most of the older mercury emissions data reported in the literature are suspect given the difficulties in mercury sampling and analysis. Since mercury amalgamates with many metals, it is ubiquitous in many laboratories and thus contaminates samples. It does appear that the more recently reported data using better sampling techniques and analytical methods are reducing some of this uncertainty. For instance, even results from early PISCES field sampling of mercury were unspectacular. Mercury recovery from the EPA multi-metals sampling train were a meager 30 to 40%. Material balances

were reporting less than 50% closure at the early test sites (Figure 5). However, with experience improvements to the sampling and analytical procedures, and frequent cross-comparisons with alternative mercury measurement methods, the accuracy and reproducibility of mercury determinations improved dramatically for flue gas, sluice water, flyash, and coal samples. Recent material balances for mercury around the power plant site are now within the 70-130% acceptance interval around the 100% closure mark.

Because of the measurement difficulty, EPRI has given specific attention to developing new methods of mercury measurement, and is cooperating with EPA in a jointly sponsored field validation test of a full-scale power plant stack gas for mercury concentrations.

The behavior of mercury in control devices such as FGD remains to be better understood. The current PISCES field data indicate about 20-90% removal for cold-side ESPs (5 data points) and 85-90% for fabric filters (3 data points). One theory to explain the higher removal percentage data points suggests that unburnt carbon carryover due to loss of ignition (LOI) may be adsorbing the element. This is a subject for follow-up research.

The dominant form of mercury in combustion gases is divalent Hg^{++} , at approximately 60% (Figure 7). Speciation properties after the boiler and in the stack emissions plume beyond the plant may depend to some extent on the HCl in the flue gas and therefore the chlorine concentration in the coal. Based on very limited mercury studies around a 4-MW pilot unit at the High Sulfur Test Center, consisting of a cold-side ESP plus wet limestone FGD combination treating bituminous coal gas, all species of mercury (methyl-, di-valent-, and elemental-) were found. Two observations are notable. First, the dominant form of mercury in the combustion flue gas was the di-valent (at approximately 60% of the total mercury); and second, the combination pilot ESP and wet FGD captured all of the di-valent mercury and all of the methyl-mercury, leaving a third of the elemental mercury behind in the emitted flue gas (Figure 7).

Several papers have reported that mercury can be removed from municipal waste incinerator flue gas through use of chemical additives. Joy Technologies[7] reported that use of an additive in a spray dryer system improved mercury removal as did operation at lower exit gas temperatures. Joy's data show that a spray dry/baghouse combination operating on a municipal waste incinerator removed 69% of the total mercury without the additive and from 91% to 95% with the additive. The spray dry/ESP combination removed from 27% to 66% of total mercury without the additive and from 78% to 86% with the additive. The higher removals were observed at the lower exit gas temperatures. Although the additive was not specified, it is assumed to be activated carbon. Use of activated carbon has been reported by others with similar results [8-11].

More recent EPRI exploratory tests were conducted with activated carbon injection just upstream of a 1-MW pilot pulse jet fabric filter system at a low sulfur subbituminous coal-fired power plant [12]. Inlet mercury concentrations ranged from 2 to 8 $\mu\text{g}/\text{Nm}^3$. When activated carbon was injected at a ratio of 4000 parts of carbon per part of mercury in the flue gas, mercury removals of better than 90% was observed at temperatures of 121°C (250°F) (Figure 8). The coal contained low chlorine concentrations and the measured ratio of ionic to elemental mercury was about 75/25. In the same EPRI study, mercury rich activated carbon was sampled for desorption effects over a four week period. No significant mercury re-volatilization was detected. Without carbon injection, the pilot fabric filter mercury removal efficiency dropped to 30 to 50%.

Because the technique of using sorbents, such as activated carbon, is promising, additional research is underway by the electric utility industry and U.S. government agencies to establish their properties and better define their applications.

Clearly, mercury is a case where more measurement and analysis is needed to narrow down the results to a point where we can be confident in predicting either the emissions or how best to reduce them.

4. Chlorides

Chloride concentrations vary widely in US coals, from virtually unmeasurable quantities to over 0.5% [13]. Generally, eastern high-sulfur coals have higher chloride concentrations than western subbituminous and lignite coals. During combustion in the furnace, over 95% of the chloride in the coal is initially released, primarily (90%) in the form of gaseous HCl. There is little interaction between the gaseous HCl and the ash. HCl will deposit onto the fly ash only below 60°C (140°F), the acid dewpoint for HCl. This is true regardless of the pH of the fly ash. Data indicate extremely low to nondetectable levels of chloride in fly ash from lignite, bituminous, and subbituminous coals. HCl reacts quickly in the atmosphere with ammonia and calcium and is generally not detected beyond 10 kilometers (several miles) from the stack.

Figure 9 shows some results of PISCES field measurements on chloride removal by different control technologies and combinations thereof, for both bituminous and subbituminous coal.

HCl emissions are not considered to be a major health concern. For a power plant emitting 200 tons of HCl per year with a stack height at GEP (good engineering practice), ground level concentrations over a one-hour maximum average would be less than 1 microgram/ m^3 under adverse meteorological conditions. This is negligible compared to the threshold limit value for occupational health effects of 7000 micrograms/cubic meter.

5. Sampling Chemical Species

The case of mercury is a good illustration of the fact that evaluating trace substance emissions is critically dependent on the ability to sample and measure these chemical species reliably, when a vast majority of those listed in the Clean Air Act Amendments only appear in trace amounts in plant process streams. Without the requisite understanding of a method's capabilities and limitations, misleading results are not only possible, but highly probable.

To assist the field measurement efforts, site-specific risk assessments were conducted with results from early testing to define minimum risk concentrations, and in turn, determined the sensitivity levels or detection levels that sample monitoring methods must attain for input towards more reasonable risk estimates. Methods, to the extent commercially available, were selected to meet these target concentrations at future test sites. Unfortunately, methods with the required sensitivity were not available for all substances.

To furnish utilities with interim guidance, EPRI has produced a compendium of available methods for measuring trace substances in a variety of process streams, including flue gas. The document contains information on precision and detection quantification limits, where available. This information will help utilities establish and conduct sampling programs based on the most up-to-date methods, and assist them in understanding the limitations of the various measurement methods. Publication of this compendium is expected by the end of 1993.

Future PISCES efforts will involve both laboratory development and field evaluation studies of specific methods for measuring important chemicals in fuels and flue gas. Besides mercury, of particular interest are improved sampling techniques for benzene and speciation of important trace elements such as arsenic and chromium.

Concerning organics, while PISCES has sampled several VOCs, formaldehyde, and PAHs, preliminary EPRI risk assessments indicate that they do not pose significant risk. Their presence is in many cases at or below detection limits of current EPA-recommended measurement methods. While VOCs are measurable, their risks are also very low.

6. Emission Factors

When emission factors are computed with the PISCES field sampling-preliminary results, two observations can be drawn (Figure 10). First, the variability of elemental measurements from the recent field studies show far less scatter than those reported in the 1989 EPA report. And second, the average emission factor values are less than those found in that same EPA report. In fact, Figure 10 shows that they could be 1 to 2 orders of magnitude apart. In the case of chromium and nickel, it is entirely conceivable that the higher literature values in the EPA report may be due to the use of stainless steel sampling probes employed to collect this historical data. Such probes were a common device for gas sampling prior to the mid-1980's. Erosion and corrosion by-products from these probes might have easily contaminated the samples.

7. Status of Field Measurement Programs

By the end of 1993, EPRI will have acquired field test data from more than 20 power plant sites. The data now available are presently being analyzed and compared. In addition, the US Department of Energy (DOE) Pittsburgh Energy Technology Center (PETC) has begun a complementary program at approximately 8 more locations. DOE-PETC are sampling for a similar set of chemicals as the EPRI FCEM program and using similar sampling and analytical protocol based on the EPRI procedures.

III. RISK ASSESSMENT

The PISCES program is one major component of EPRI's utility trace substances R&D. It is designed to interface closely and interactively with the second key component - the risk assessment CORE project (Figure 11). CORE (Comprehensive Risk Evaluation) is an effort to integrate the state of our knowledge about trace substances, their behavior in the environment, and particularly the ways in which they might impact human health. The CORE project has two key goals. First, given the measurement information from PISCES and other projects, what can be said about the emissions and fate of trace substances from the U.S. power industry as a whole? And second, in light of what has been learned about atmospheric processes, ecosystems, and human health response, what can be concluded about the health risks due to these substances from power plants? What does this imply for the industry of today, and the industry of the 21st century?

In order to clarify these questions, CORE is carrying out an integrated assessment of these trace substances from the time they are emitted from a power plant up to the point that human populations might be exposed to them some time later. This assessment is relying on tools in the EPRI risk assessment arsenal to evaluate the risks due to the national capacity. These tools include TRUE, a multimedia risk assessment model, and the Core Risk Assessment Framework. The latter brings together the data from PISCES, calculates emissions from each power plant in the nation, computes downwind deposition and concentrations by substance, and allows us to estimate human health risks by a number of means.

As part of this Framework, EPRI has developed a number of advanced applications applicable to future assessments of human health risk. These include a database of population distributions around every power plant, a probabilistic model of human activity patterns, the effects of indoor environments on exposures, a quantitative model of uncertainties in risk assessments, and a national assessment of mercury exposure from the industry. These results, together with EPRI's efforts to determine the composition and biological effects of utility flyash, the chemistry of trace substances in plumes and in the atmosphere, and the ecological cycling of mercury, are being brought together in the Air Toxics Synthesis Report, scheduled for late 1993.

IV. COLLABORATIVE EFFORT TO IMPROVE THE STATE OF KNOWLEDGE

The current R&D pace in this important area could not have been maintained and would be much less focused without the cooperative spirit among key organizations and agencies: EPRI, DOE, UARG, EPA. Each separate organization has played a complementary and constructive role towards a collectively defined goal or completing the CAAA-mandated utility study.

The need for better scientific data on utility emissions and impacts, as confirmed by PISCES and other work in this area, was a factor in the congressional decision to allow more time for specific study. The results of the industry-government coordination of respective research efforts should enable both parties to make decisions based on the best scientific and technical information available.

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- [3] Clarke, L. and Sloss, L., "Trace Elements-Emissions from Coal Combustion and Gasification," IEA Coal Research, IEACR/49, July 1992.
- [4] Behrens, G.P. and Chow, W., "Use of A Multi-Media Database for Chemical Emission Studies of Conventional Power Systems," Presented at the Air & Waste Management Association Annual Meeting, Pittsburgh, Pa., June 1990.
- [5] Porcella, Donald, EPRI, private communications.
- [6] Nriagu, J.O. and Pacyna, J.M., "Quantitative Assessment of Worldwide Contamination of Air, Water and Soils by Trace Metals," Nature, Vol. 333, May 12, 1988, Pages 134-139.
- [7] Donnelly, JR and Felsvang, KS, "Joy/Niro SDA MSW Gas Cleaning System: New Developments," paper presented at the Air & Waste Management Association Annual Meeting, Anaheim, Ca., June 1989.
- [8] Teller, Aaron and Quimby, Jay, "Mercury Removal from Incineration Flue Gas," paper presented at the 84th meeting of the Air & Waste Management Association, Vancouver, BC. June 16-21, 1991
- [9] Volland, Craig S., "Mercury Emissions From Municipal Solid Waste Combustion," paper presented at the 84th meeting of the Air & Waste Management Association, Vancouver, B.C. June 16-21, 1991.
- [10] Guest, Terrence L., and Knizak, Ota, "Mercury Control at Burnaby's Municipal Waste Incinerator," paper presented at the 84th meeting of the Air & Waste Management Association, Vancouver, B.C. June 16-21, 1991.
- [11] Riley, et. al., "Removal of Heavy Metals and Dioxin in Flue Gas Cleaning After Waste Incineration," paper presented at the 84th meeting of the Air & Waste Management Association, Vancouver, BC, June 16-21, 1991.
- [12] Chang, R. and Owens, D., "Developing Methods for Mercury Removal from Power Plants," presented at the Second International Conference on Managing Hazardous Air Pollutants, Washington, DC, July 1993.
- [13] Coal Conversion Systems Technical Data Book, U.S. DOE, Division of Coal Conversion, under DOE Contract No. EX-76-C-01-2286, March 1982.

TABLE 1

Chemicals for PISCES Field Emissions Monitoring

INORGANICS

Arsenic (incl. +3,+5)

Barium

Beryllium

Cadmium

Chlorine/Hydrochloric acid

Chromium (incl. +6)*

Cobalt

Copper

*Radionuclides**

Fluorine / *Hydrofluoric acid*

Lead

Manganese

Mercury [incl. methyl-, 0, +2*]

Molybdenum

Nickel

Phosphorus/Phosphate

Selenium

Vanadium

ORGANICS

Benzene

Toluene

Formaldehyde

*Dioxins/Furans**

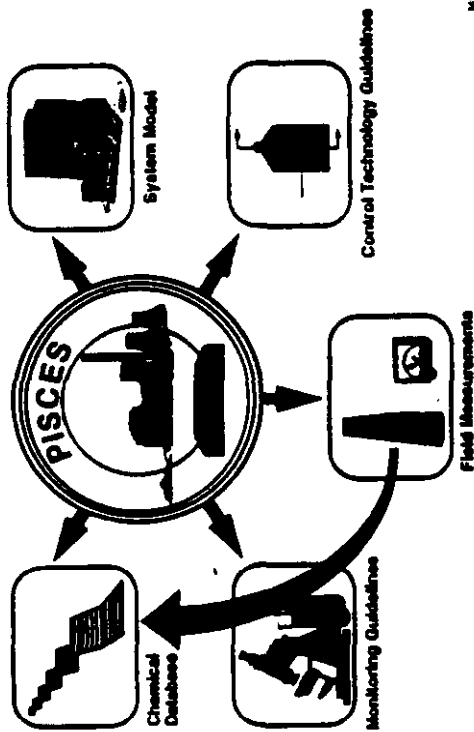
Polynuclear Aromatics

(e.g., Benzo-a-pyrene)

* Measured at Selected Plants

FIGURE 1

POWER PLANT INTEGRATED SYSTEMS: CHEMICAL EMISSION STUDIES



March 14

FIGURE 3

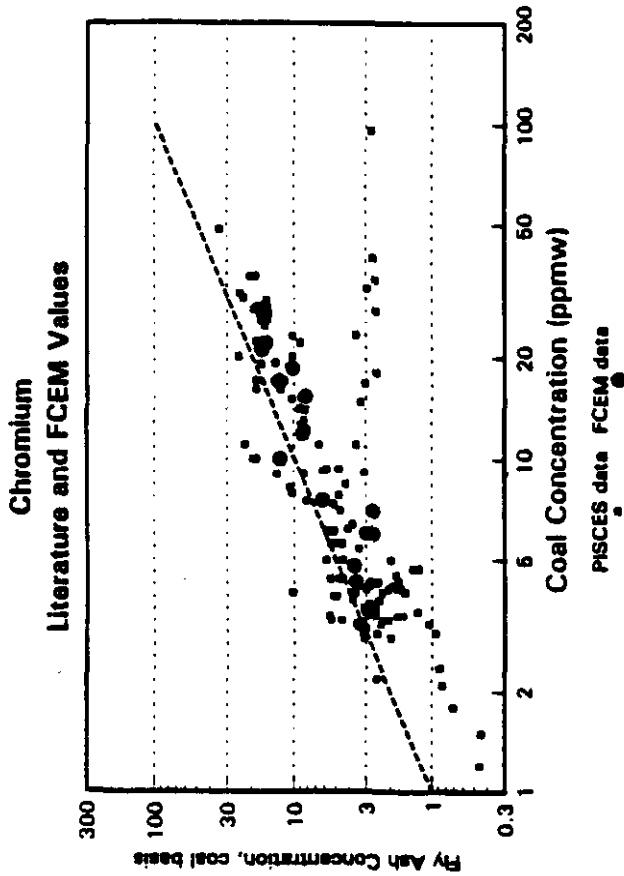


FIGURE 2

Comparison of Stack Emission Rate with Inlet Mass Rate Midwest Plant — ESP & Wet Limestone FGD

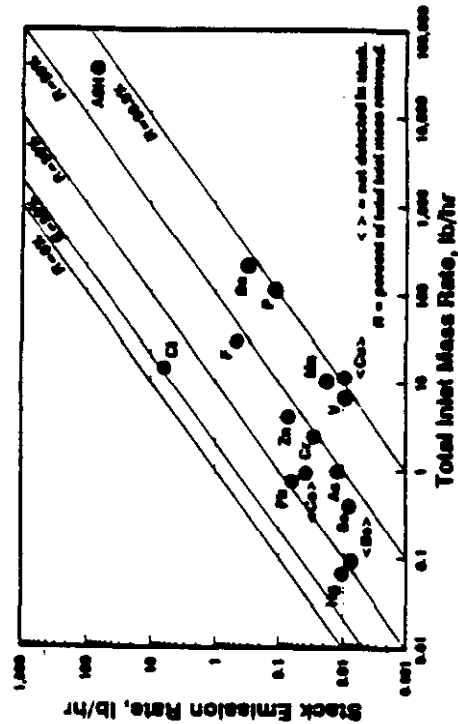


FIGURE 4

ESP Removal Efficiency: 3 FCEM Sites

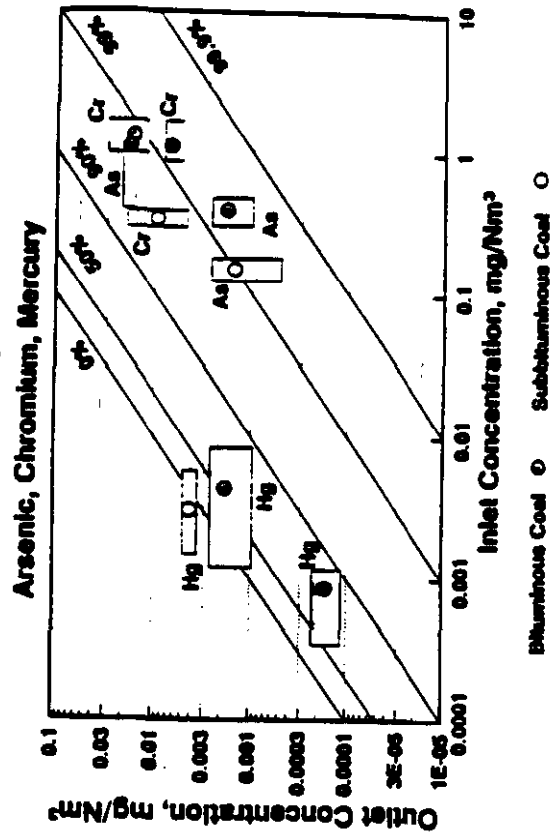


FIGURE 5

Comparison of Material Balance Closures

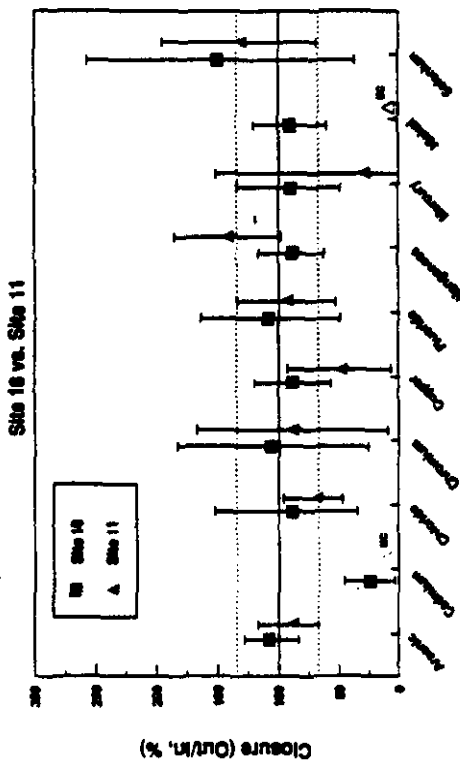


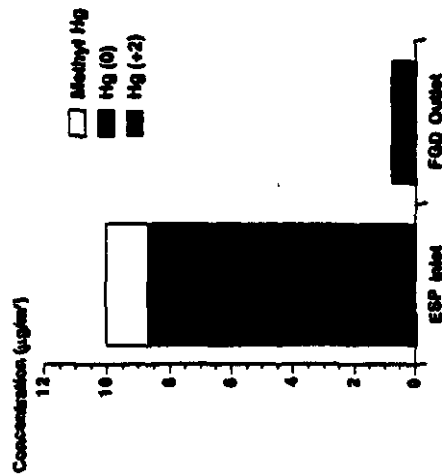
FIGURE 6

THE SPECIAL CASE OF MERCURY

EMISSIONS	OTHER AIR TOXICS	MERCURY
DEPOSITION	• Particle-bound	• Vapor
EXPOSURE ROUTE	• Wet - Dry	• Dry(O), wet(W)
	• Inhalation	• Ingestion
	• Ingestion	• (Inhalation)
MODE OF ACTION	• Carcinogens	• Neurotoxin
	• Teratogens	
SENSITIVE INDIVIDUALS	• General Population	• Fetuses, children
DOSE-RESPONSE		
EVIDENCE	• Animals	• Human
	• (human epidemiology, occupational exposures)	

FIGURE 7

MERCURY EMISSIONS SPECIATION ESP/FGD (wet) Performance



14-1064-26

FIGURE 8

Pilot Scale Evaluation of Carbon for the Removal of Trace Metals

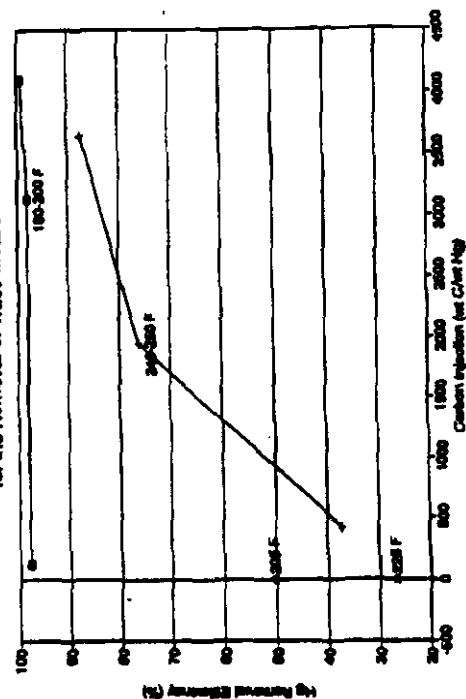


FIGURE 9

Control Device Removal Efficiency

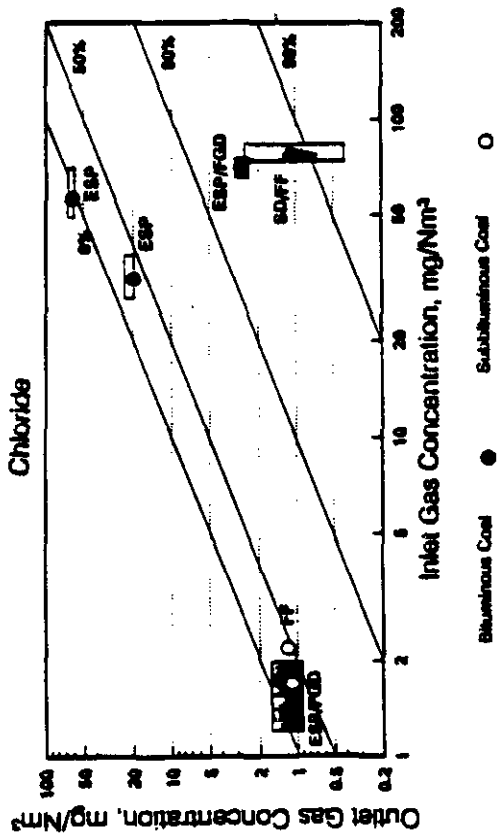


FIGURE 10

Emission Factors for Bituminous Coal w/ ESP Control

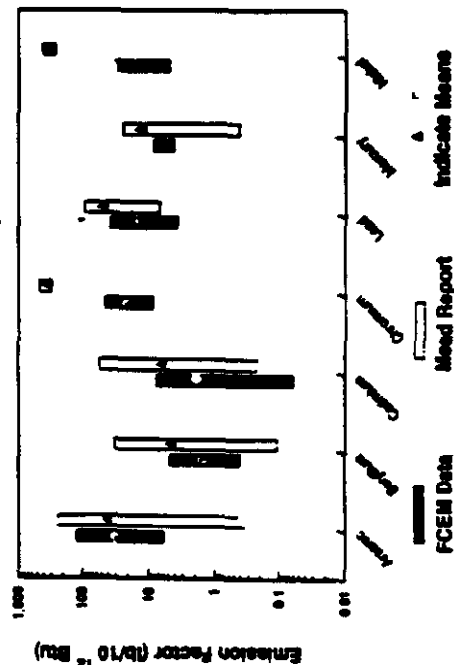
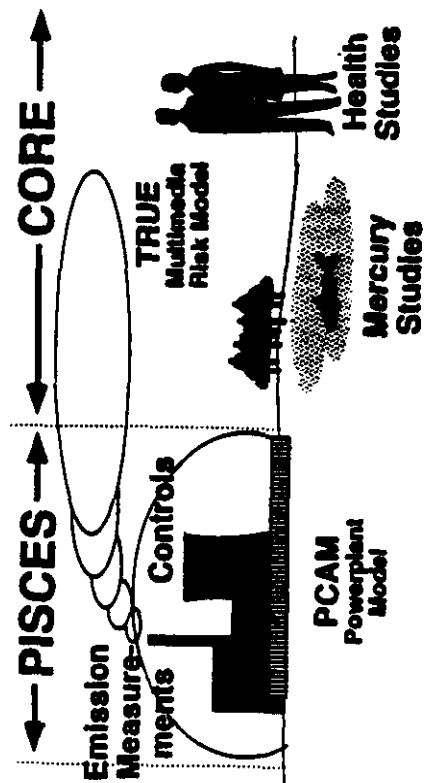


FIGURE 11

EPRI AIR TOXICS RESEARCH



**NO_x CONTROL ACCOMPLISHMENTS
AND
FUTURE CHALLENGES FOR COAL-FIRED BOILERS**

**Presented at the
Second Annual Clean Coal Technology Conference**

September 9, 1993

Atlanta

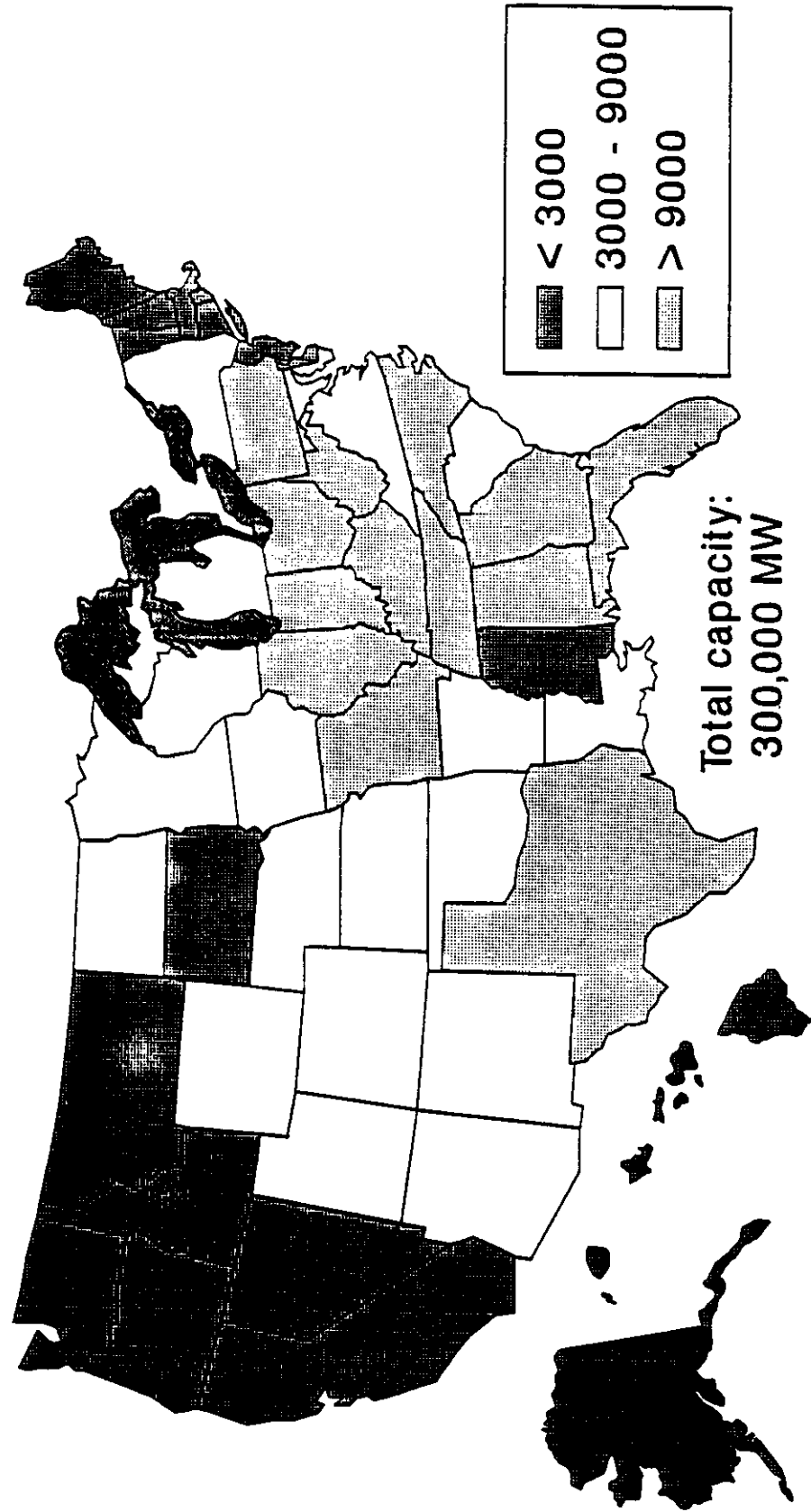
David Eskinazi, EPRI

[illegible]

ACCOMPLISHMENTS

0751D.42

U.S. COAL-FIRED GENERATING CAPACITY



Data: From DOE, December 1990.

RETROFIT NO_x CONTROLS

Coal-Fired Boilers

Technology	Emission Reduction Potential (%)	Capital Cost (\$/kw)	Operating Cost (mills/kWh)	Technology Application Issues
LNB	40-55	5-20 ²	<1	<ul style="list-style-type: none"> Primarily for wall-fired Not for cyclones
LNB ¹ + OFA	30-65	10-25 ²	<1	<ul style="list-style-type: none"> Upper furnace residence times and coal properties Not for cyclones
Reburn	40-60	20-50 ²	1-3	<ul style="list-style-type: none"> Upper furnace residence times
SNCR	35-60	5-20	<2	<ul style="list-style-type: none"> Flue gas temperature, duty cycle and size
SCR	70-90	50-150	4-8	<ul style="list-style-type: none"> Coal properties space availability, by-products, and duty cycle
NO _x /SO ₂	70-90	300-400 ³	11-15 ³	<ul style="list-style-type: none"> Under development

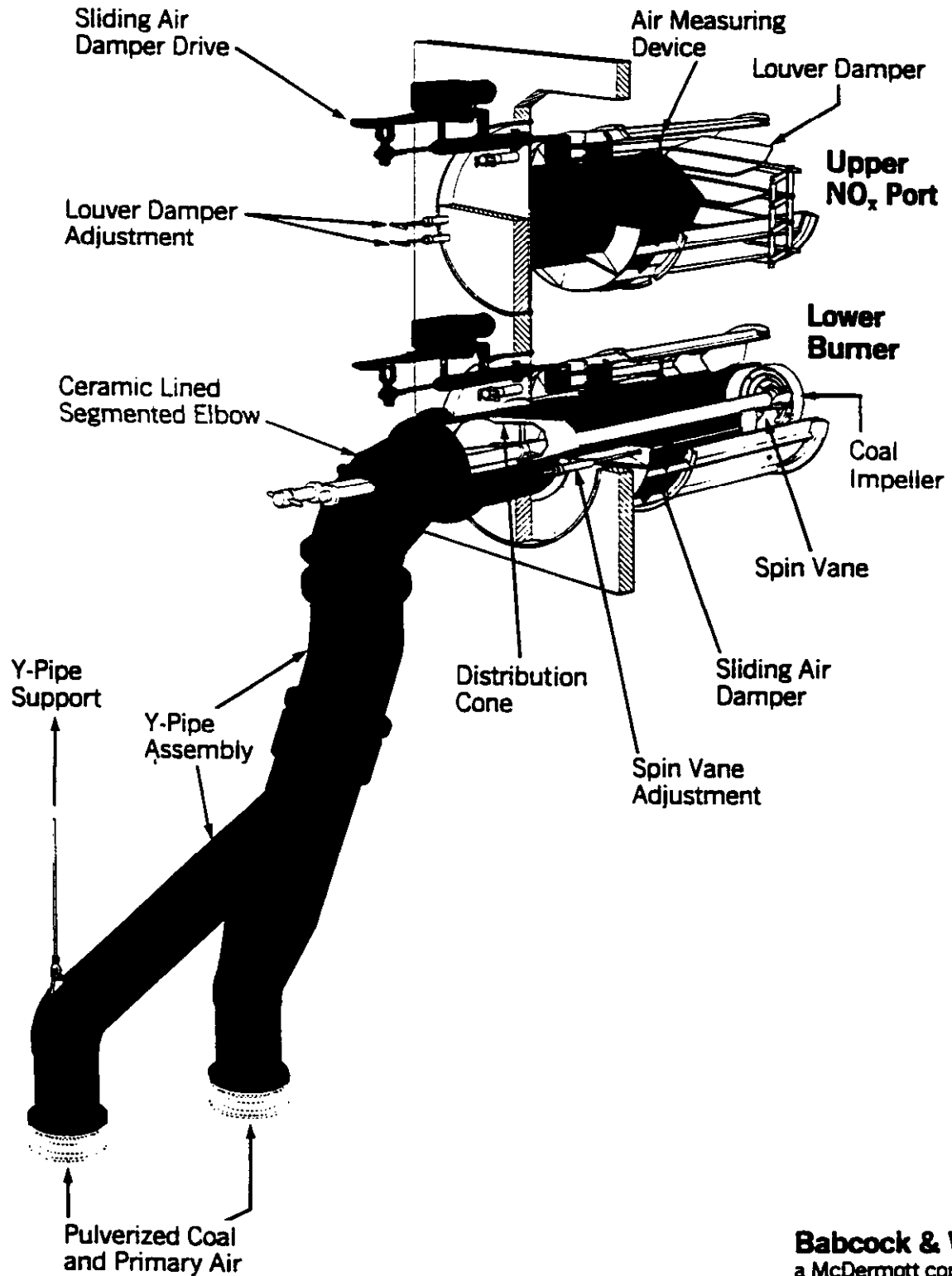
1. Includes coal and air nozzle modifications for tangential boilers.

2. Process capital costs only.

3. Includes SO₂ control.

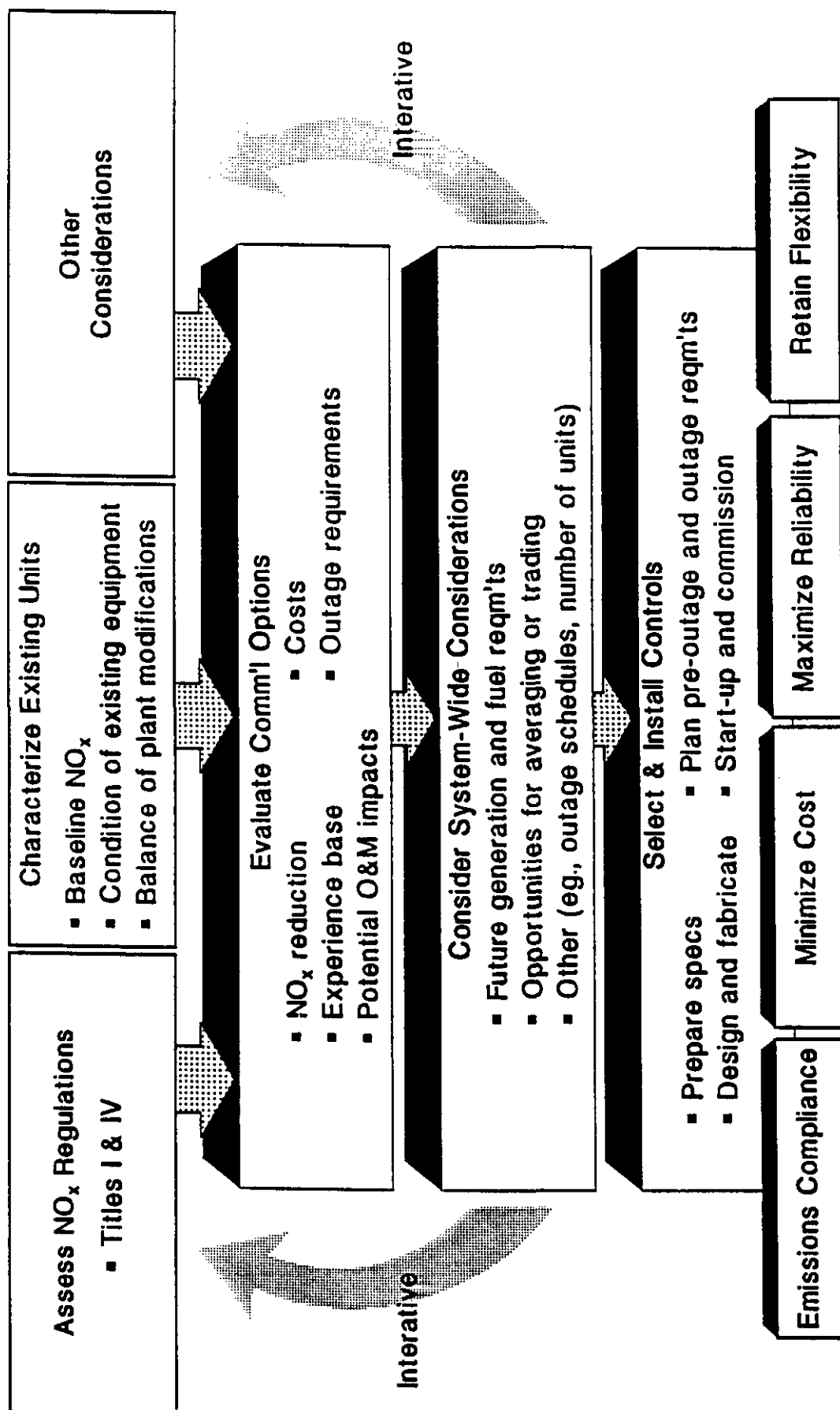
0751D.37

Low NO_x Cell Burner



Babcock & Wilcox
a McDermott company
August 1990

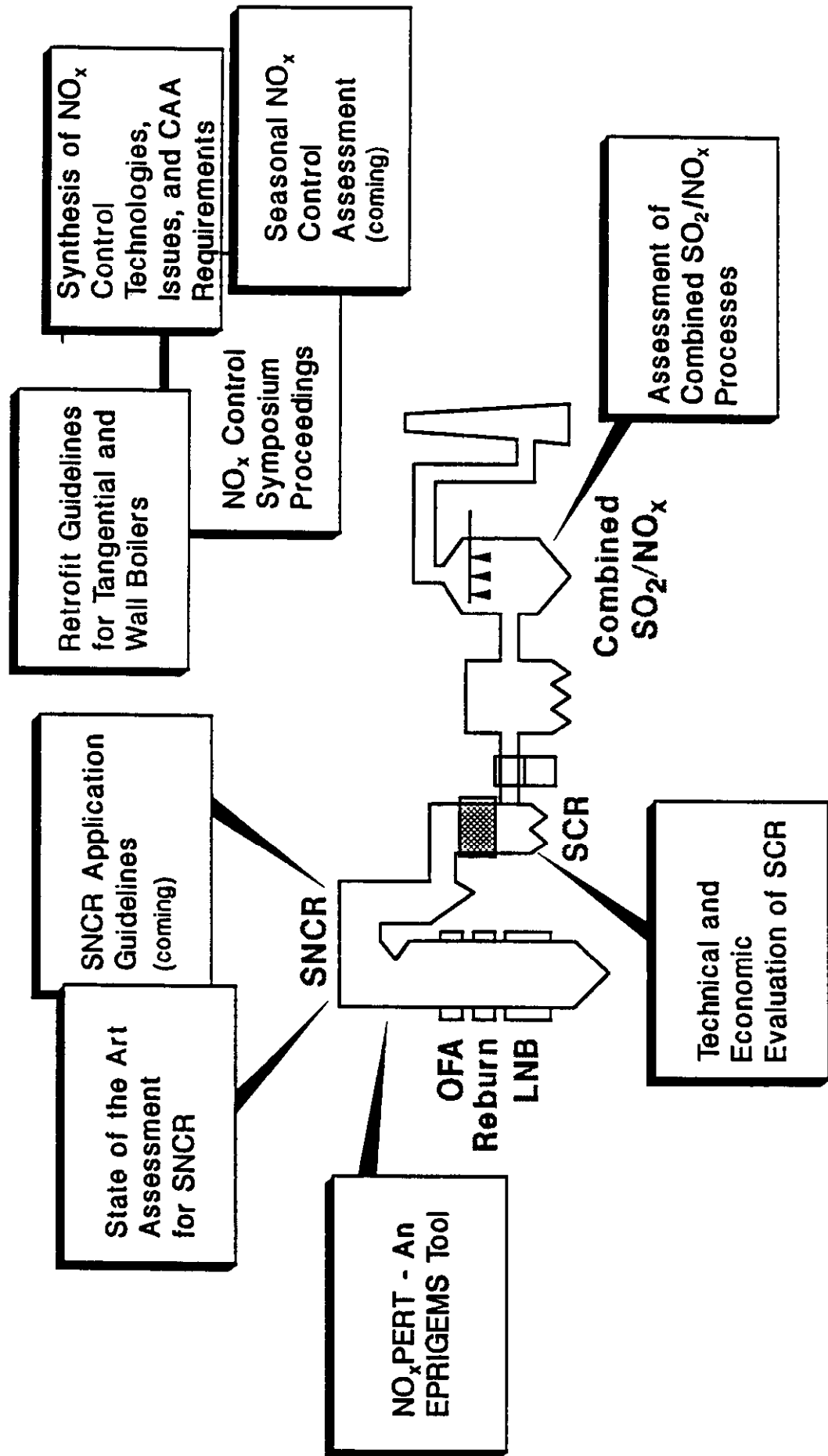
NO_x COMPLIANCE PLANNING



0751D.38

RETROFIT NO_x CONTROLS FOR COAL-FIRED BOILERS

1993 EPRI Products

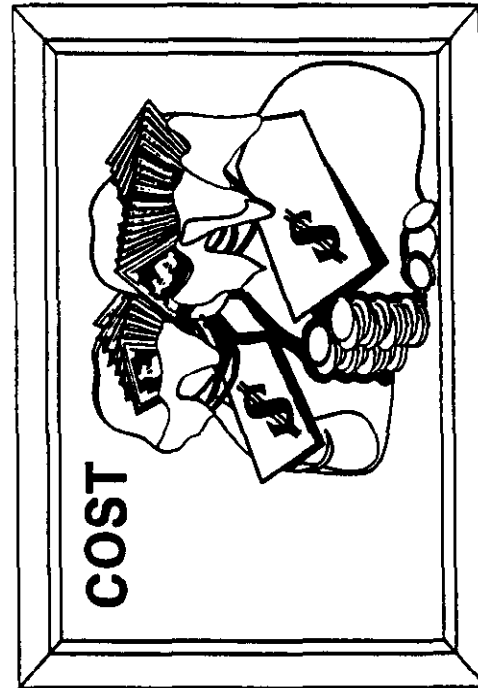
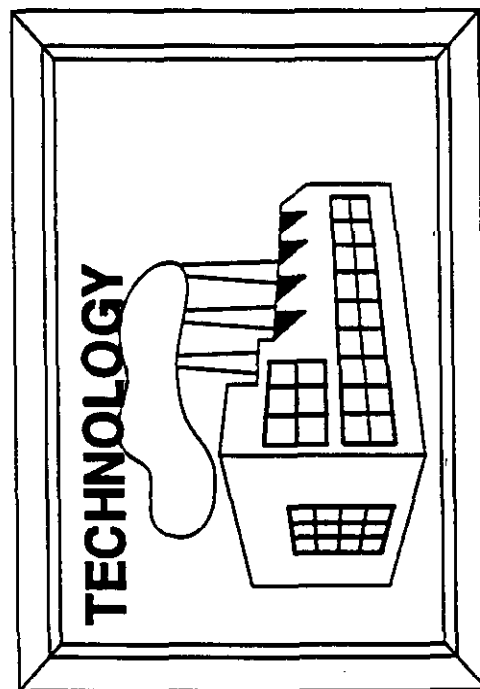
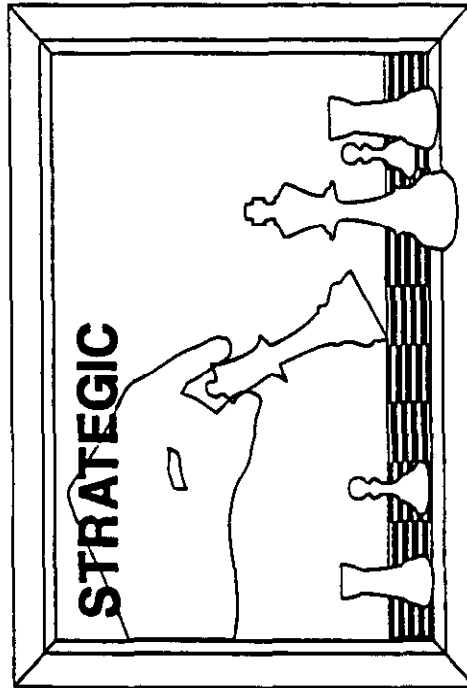
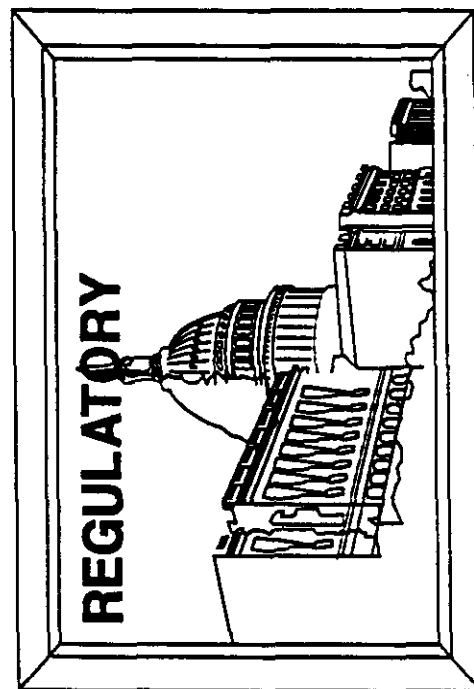


0751D.40

CHALLENGES

0751D.43

EMERGING NO_x ISSUES



REGULATORY

- Title IV
- Title I
- Future

STRATEGIC

- Advanced generation
vs. refurbishment
- Fuel selection
- Integration with heat rate
of other environmental goals

TECHNOLOGY

- Commercial development and acceptance
- Supplier design and manufacturing capabilities
- Optimization and troubleshooting
- New developments

COST

- Extent of balance of plant modifications
- Documenting operating costs
- Reducing capital costs

STATE EXTERNALITY TRENDS

**Joseph Van den Berg
Director, Technical Services
Edison Electric Institute**

Electrifying a Competitive Future

60 Years of Progress!

The Obligation to Serve



To be ready to serve you, your Electric Company must keep ahead of the growth of our community.

Public service carries with it the obligation to serve, instantly and constantly.



When you press a button or flick a switch, you want - and must have - *SERVICE* - at once, and for as long a time as you need it.

To give this service we constantly increase our facilities, planning years ahead; raising new money for extensions and betterments, and spending that money in your service.

Our obligation is to serve you. We shall continue to fulfil it to the best of our ability.

Name of Light and Power Company

CITY AND STATE ADDRESS

Taxes, like chickens, always come home to roost

*Once an incident of little moment, taxes
have today become a factor of great
concern to every citizen and business.*

This is true of electric light and power users, and of the companies that sell them the service. A national average of ten cents of every dollar paid by users of domestic electric service in 1931 merely passed through the hands of power companies and on into the treasuries of local, county, school or other district, state or federal tax-collecting agencies. Out of every dollar collected for service in 1931 by this company cents were paid out in taxes.

Users of our service pay not only their own taxes, but also pay additional taxes through their light and power bills, just as they pay extra taxes through rent, food, clothing and everything else they buy.

It should be remembered that placing special or extra tax burdens on electric light and power companies, or their product, directly increase the tax burden of users of electric service.

Name of Light and Power Company

CITY AND STATE ADDRESS

MOTHER: COME OUT OF THE KITCHEN



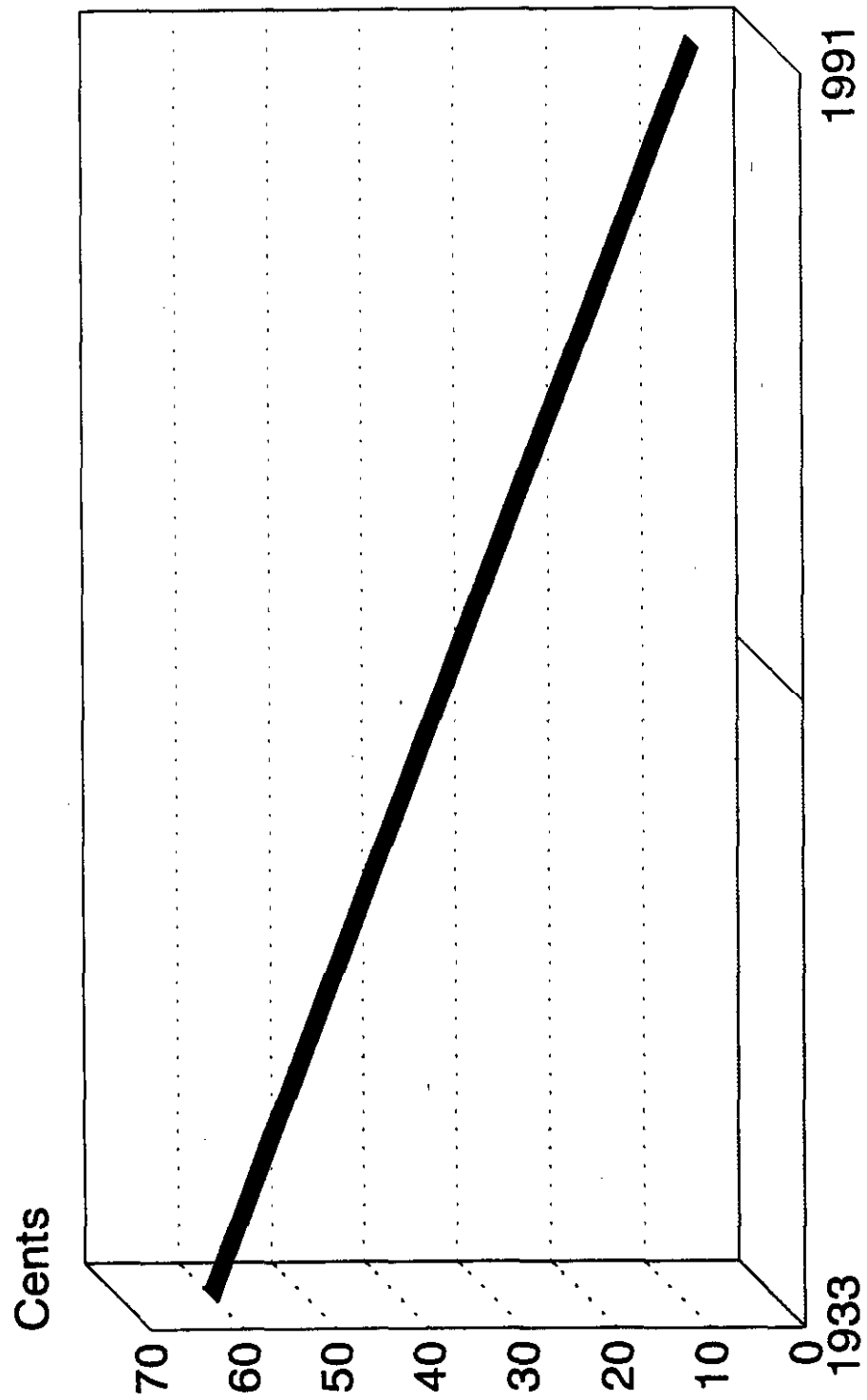
ELECTRIC COOKING SAVES
ANTIQUE KITCHENS ARE NOW USED IN PARLORS

Source: Duke Power Company Archives

EEI 1993

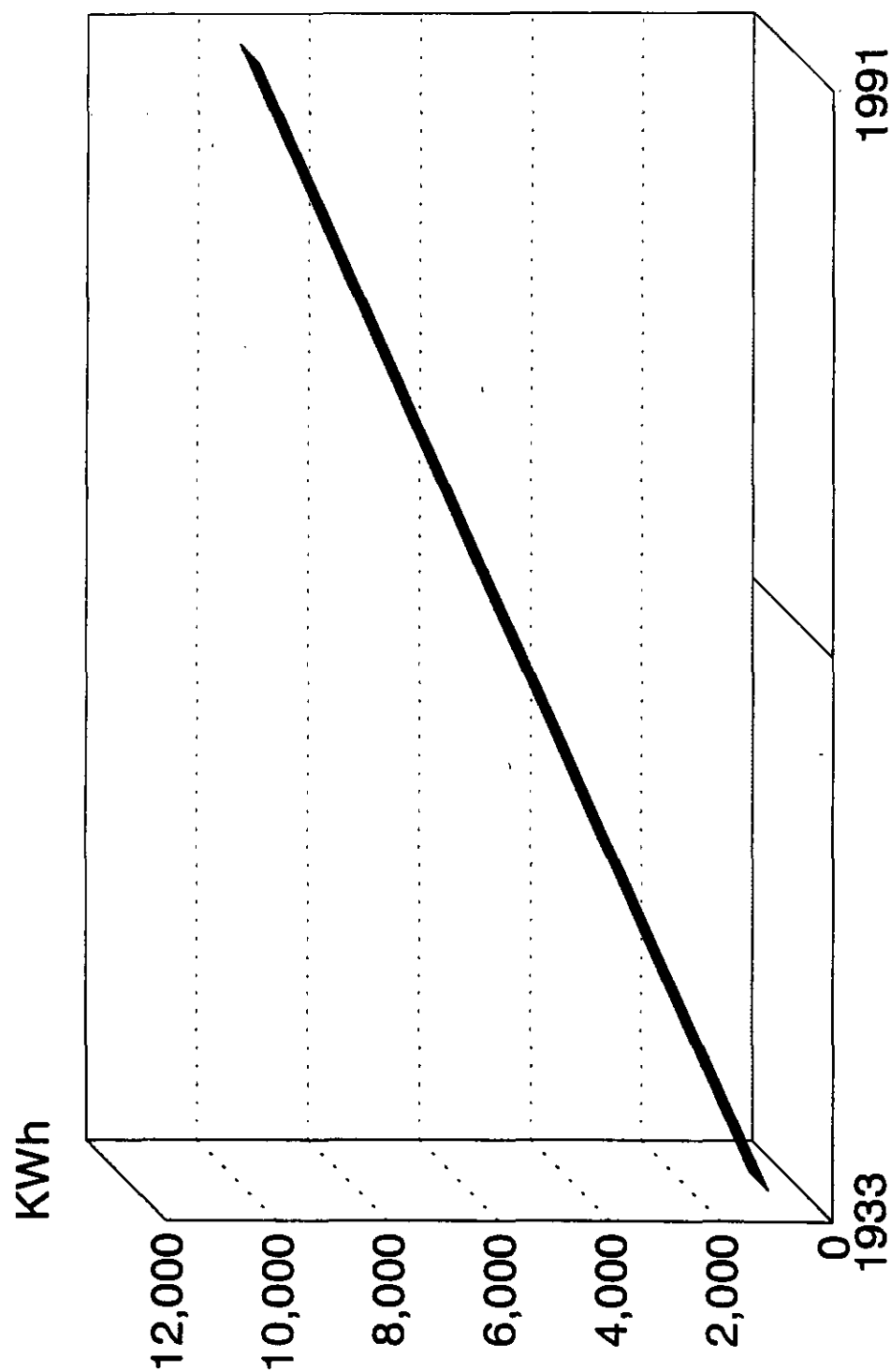
Average Residential Cost Per KWh

Inflation Adjusted, in \$1992



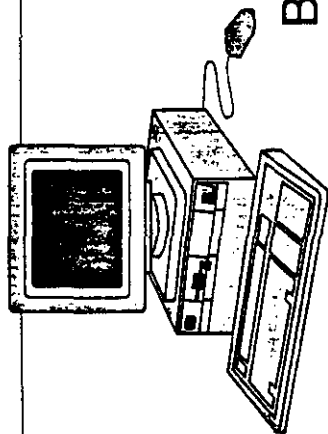
Source: Electric Perspectives, May-June 1993

Average Residential Electricity Consumption

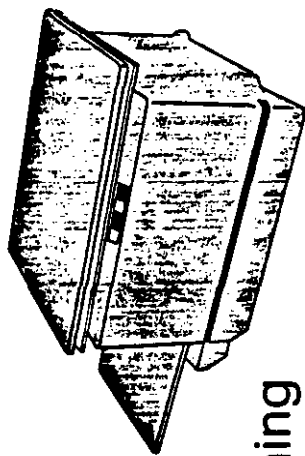


Source: EEI statistics
Residential Energy Consumption statistics, EIA, Feb. 1993

30 Products That Changed Our Lives



Personal Computer



Bar Coding/Scanning

Microwave Oven

Integrated Circuits

Photocopying Machine

Automated Teller Machine

Hand-Held Pocket Calculator

Telephone Answering Machine

Fax Machine

Velcro Fastener

Birth Control Pill

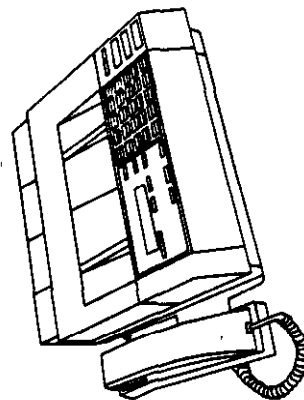
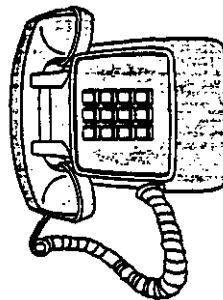
Touch-tone Telephone

Home Videocassette Recorder

Laser Surgery

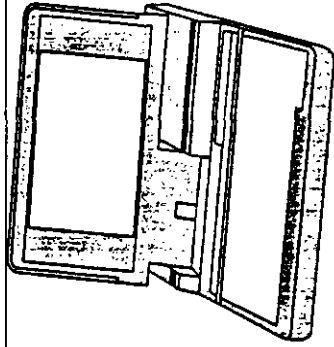
Communications Satellites

Apollo Lunar Spacecraft



Source: R&D Magazine, September 28, 1992

30 Products That Changed Our Lives



Computer Disk Drive

Organ Transplant Surgery

Fiber-optic Transmission Systems

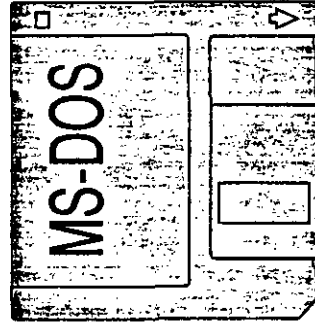
Disposable Diaper

Disk Operating System

(MS-DOS)

Magnetic Resonance

Gene-splicing Techniques



Microsurgery Techniques

Camcorder

Space Shuttle

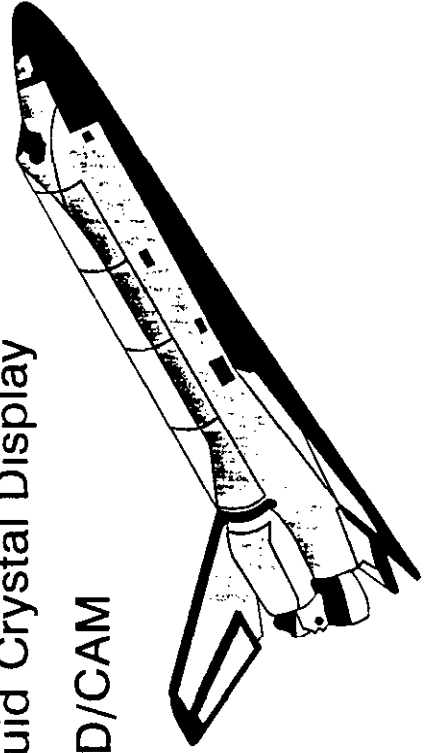
Home Smoke Alarm

Computer Aided Tomography

(CAT scan)

Liquid Crystal Display

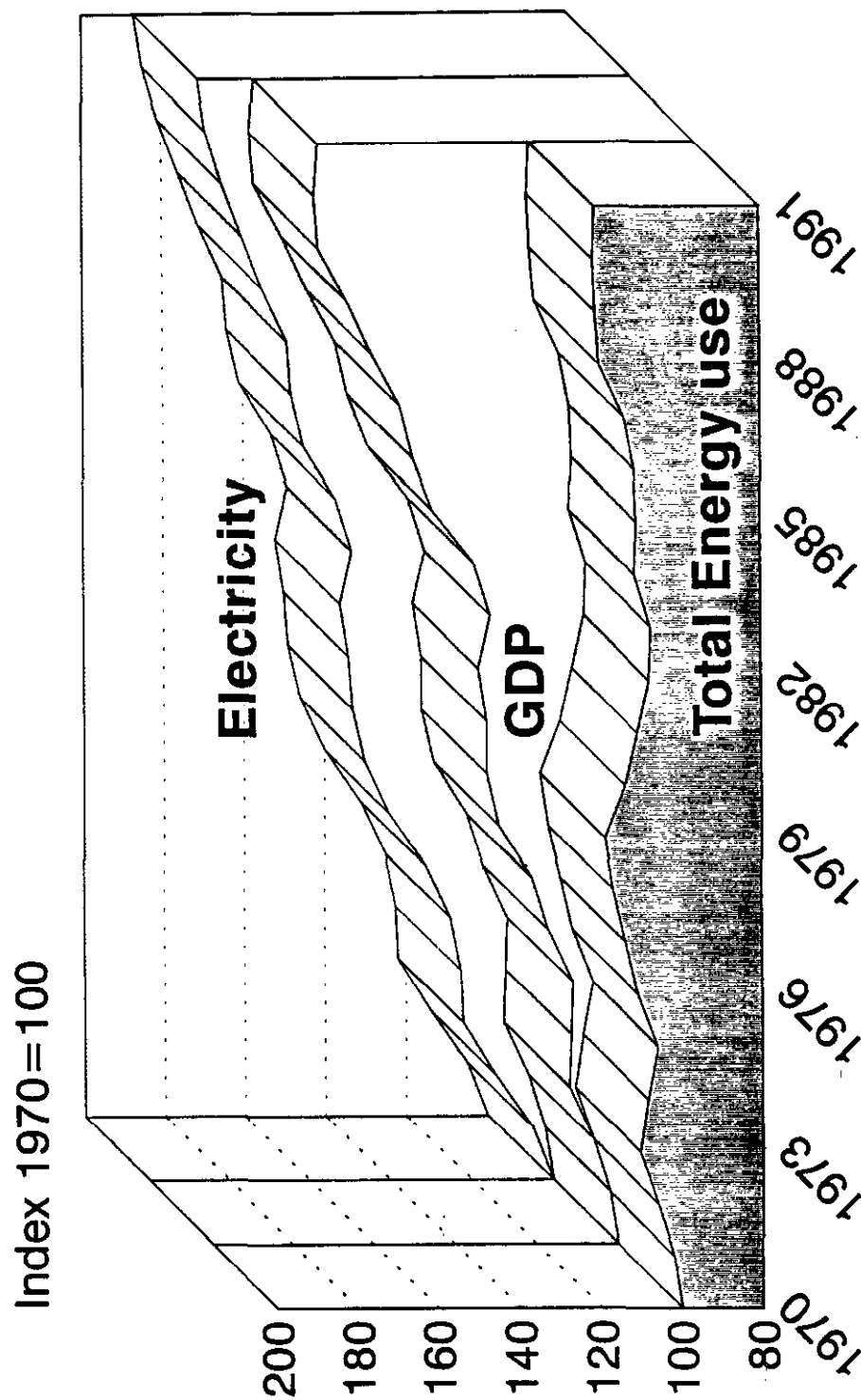
CAD/CAM



Electrotechnology Benefits

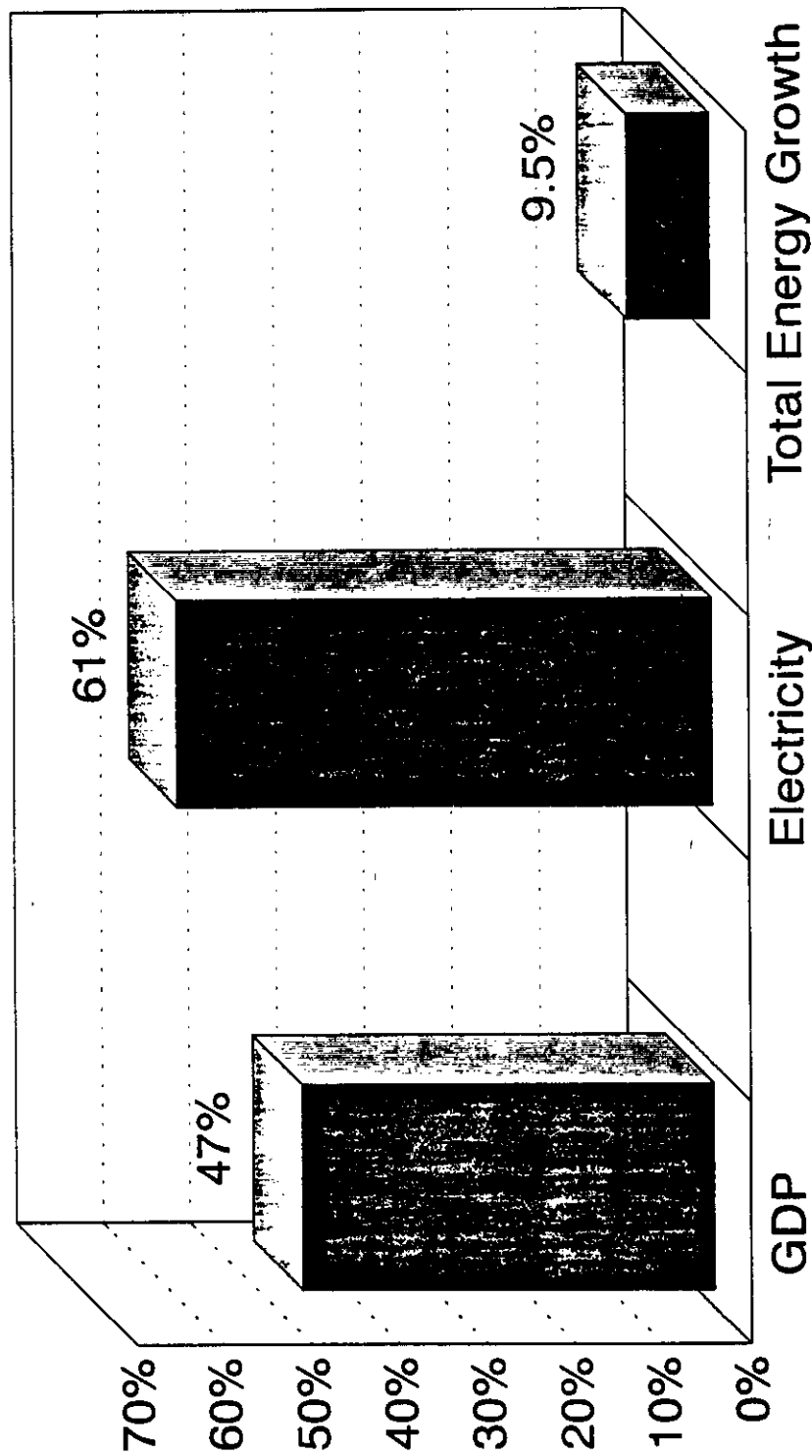
- Increased Productivity and Improved Product Quality
- Lower Emissions in Most Cases
- Safer Work Environment
- Improves Competitiveness
- Less Overall Energy Consumed in Most Cases

Electricity, Energy, and Electricity Growth 1970 - 1991



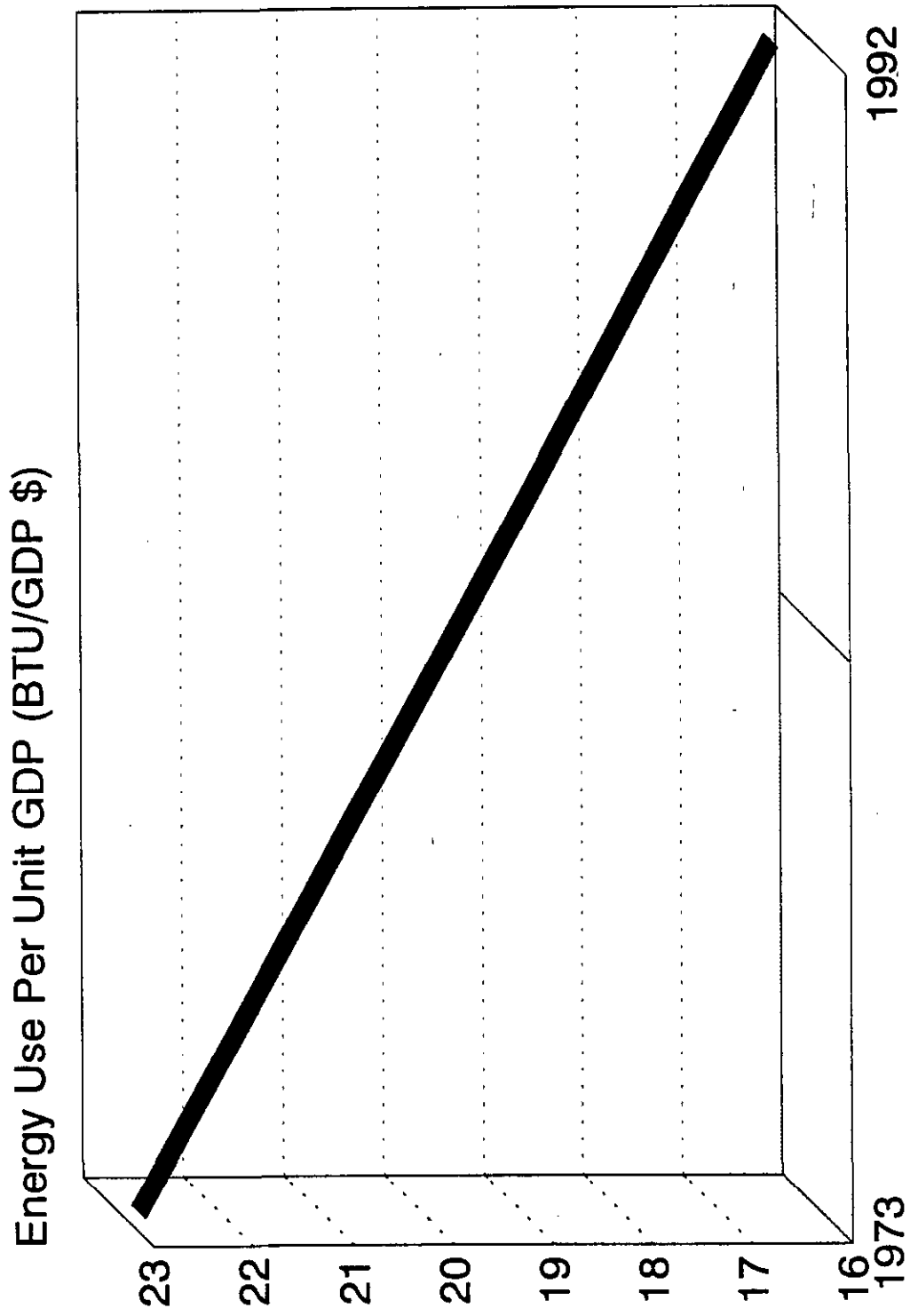
Source: U.S. Department of Commerce; Energy Information Administration

Changes in GDP, Electricity Sales, and Total Energy Use 1973 - 1991

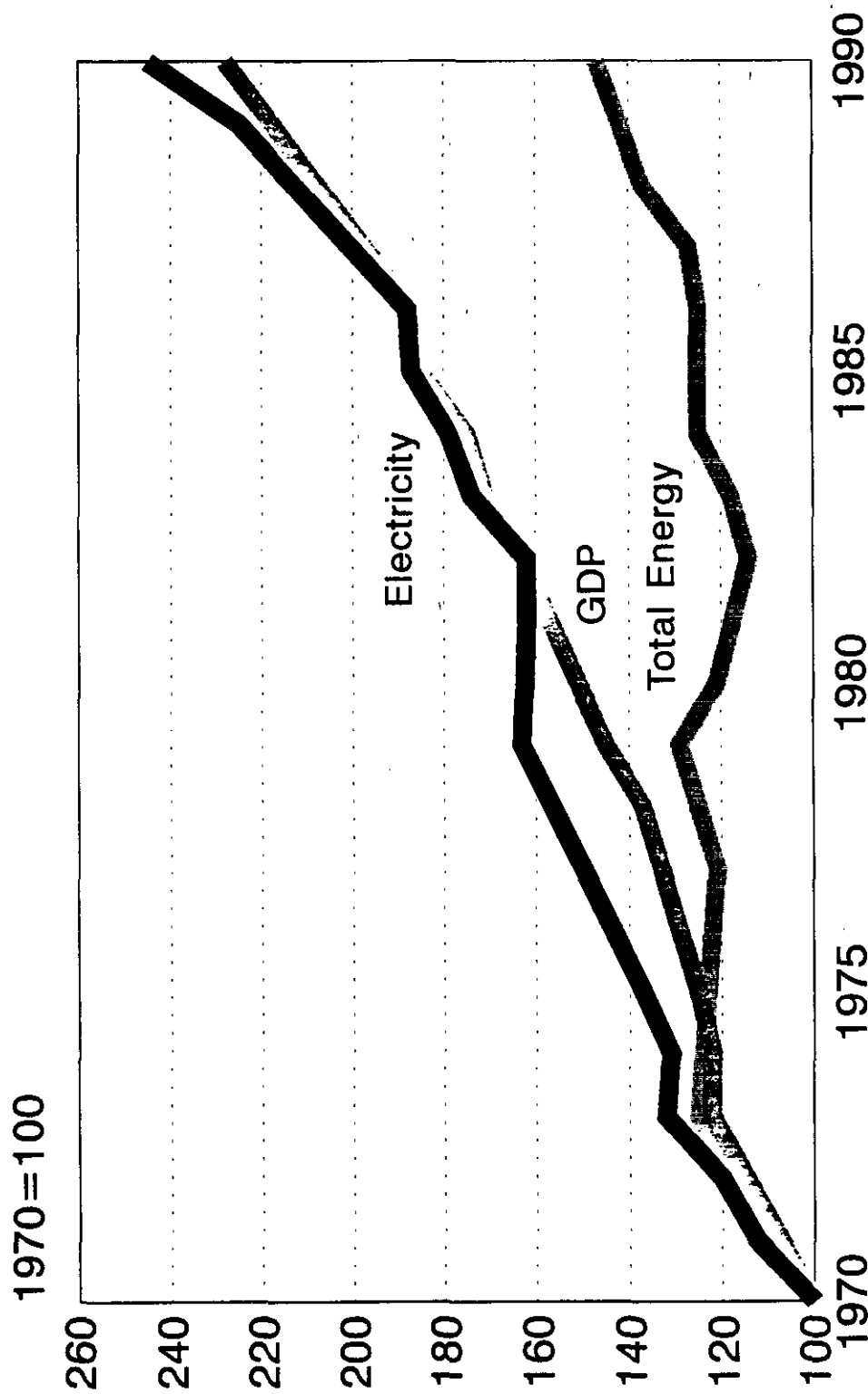


Source: U.S. Department of Commerce; Energy Information Administration

U.S. Energy Use 1973 to 1992

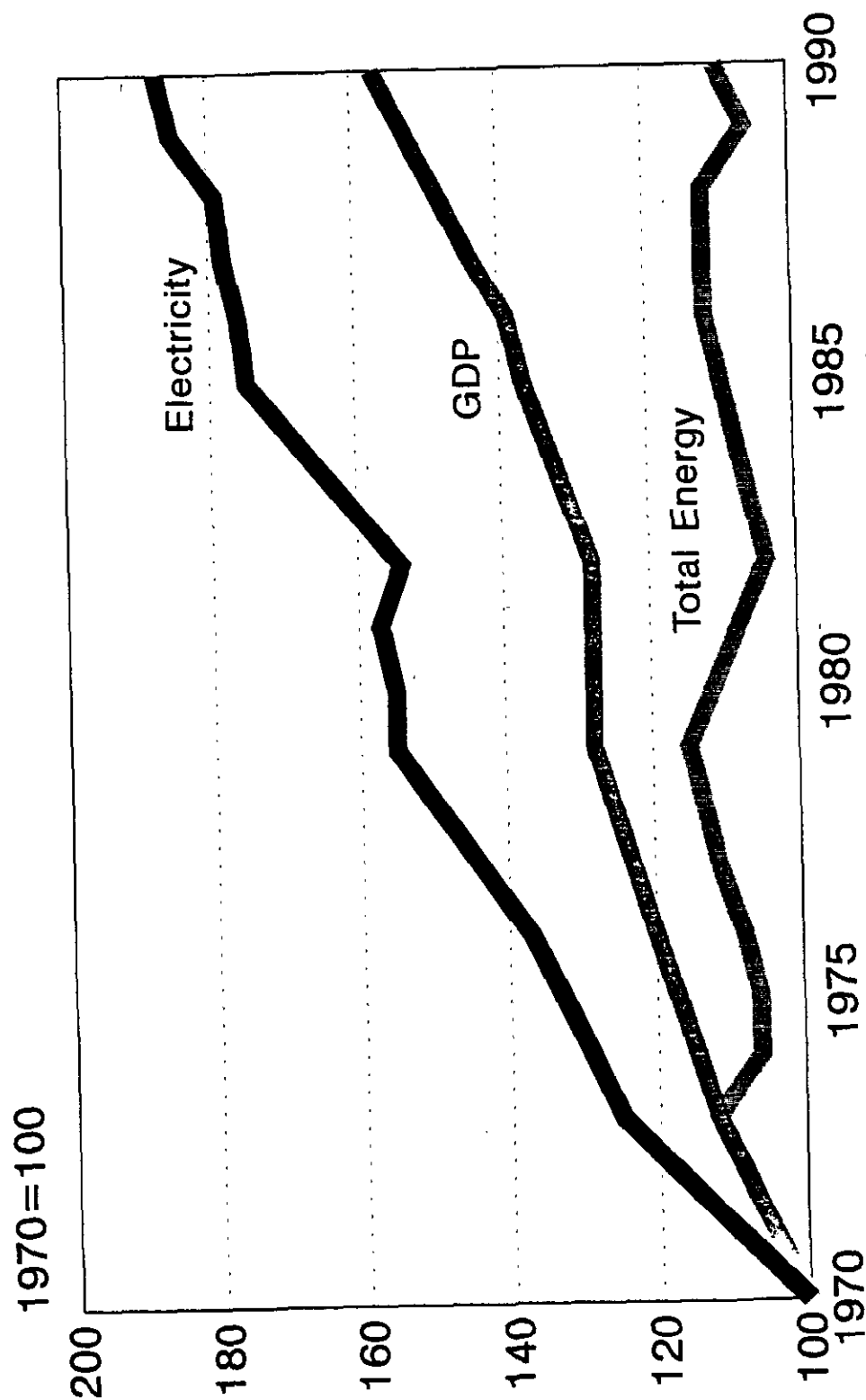


Changes in GDP, Electricity Sales, and Total Energy Use Japan Trends: 1970 - 1990



Source: Mills•McCarthy & Associates

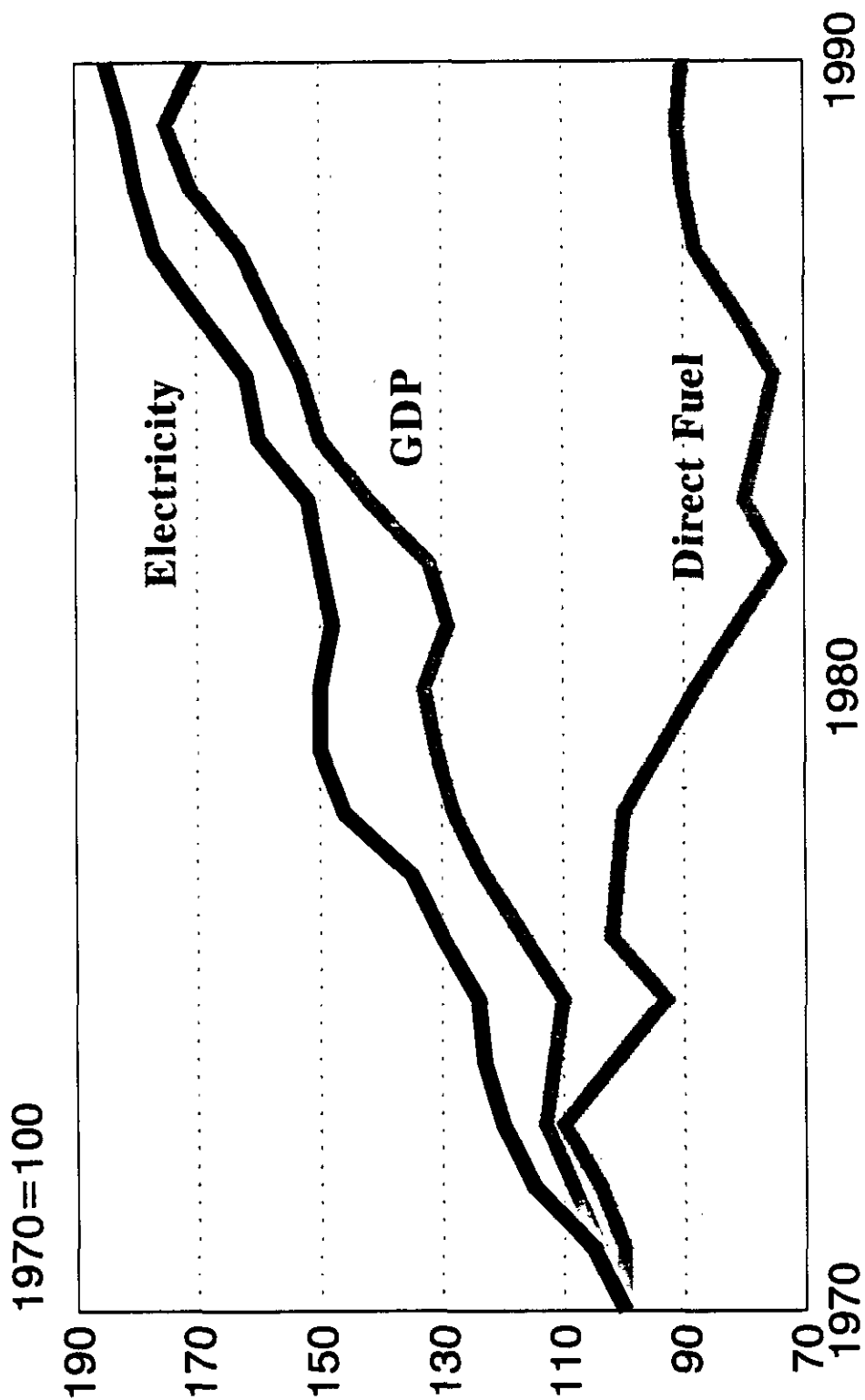
Changes in GDP, Electricity Sales, and Total Energy Use Germany Trends: 1970 - 1990



Source: Mills • McCarthy & Associates

U.S. Trends 1970-1990

(Excludes Transportation)



Electricity Consumption Follows GDP, Promotes Growth

"To Foster Increased Productivity, Policy Should Stimulate Increased Efficiency of Electricity Use, Promote the Implementation of Electrotechnologies When They Are Economically Justified, and Seek to Lower the Real Costs of Electricity Supply."

National Academy of Sciences, 1986

"Historically, technical change exploiting the special qualities of electricity has contributed to increased productivity and thereby increases in gross national product. We can expect this trend to continue."

National Academy of Sciences, 1986

"Technology is the engine of economic growth. In the United States, technological advance has been responsible for as much as two-thirds of productivity growth since the Depression."

Technology for America's Economic growth,
A New Direction to Build Economic Strength,
President Clinton, Vice President Gore, February 1993

Electricity - The Preferred Fuel

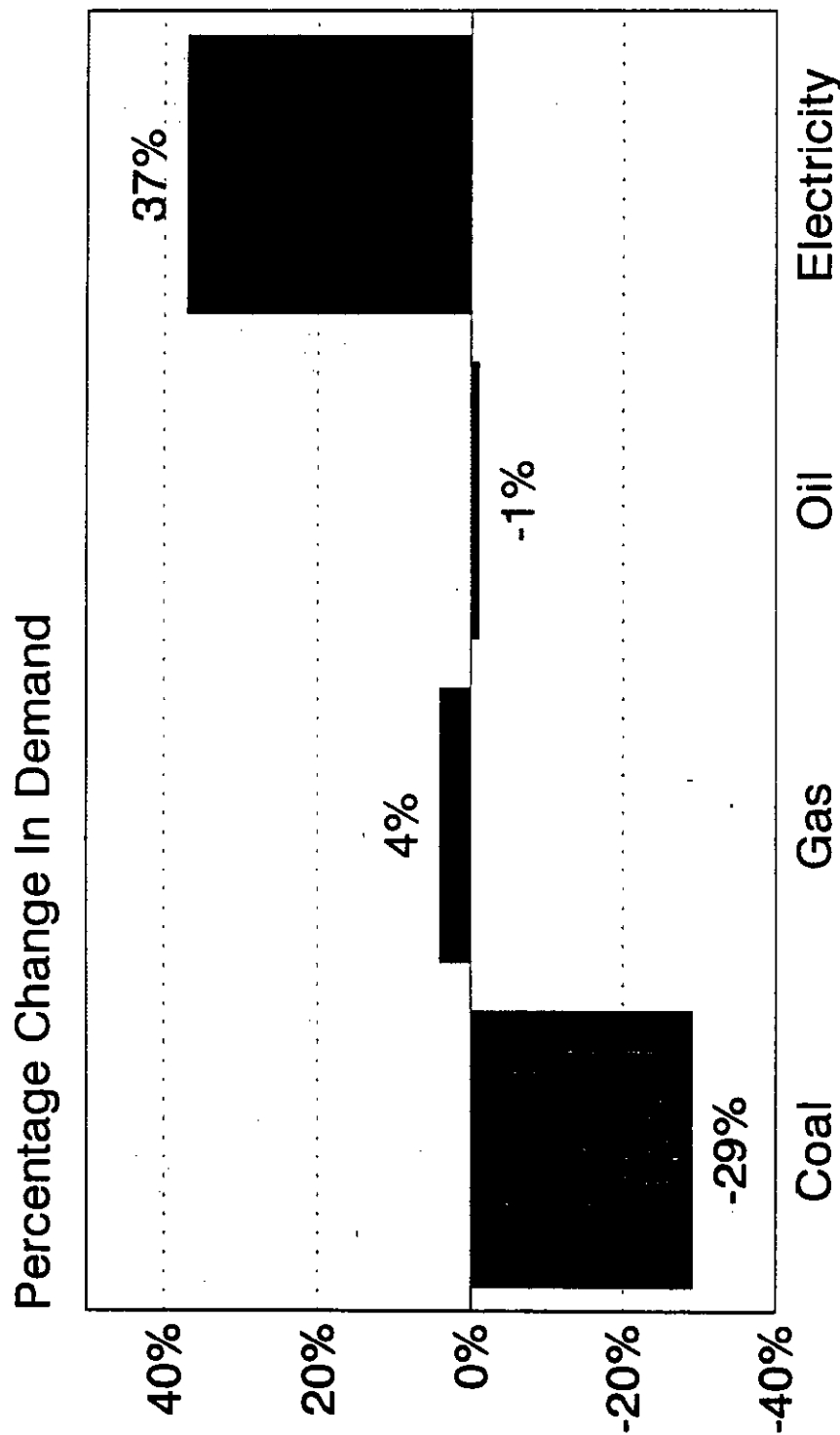
"...the trend toward electricity as the preferred energy form for manufacturing continues."

Second Biennial Report,
National Critical Technologies Panel.
January, 1993.

"Use of electricity grew faster than other energy sources during 1960 to 1990.... The Growth is the result of electricity's superior quality, flexibility, and environmental cleanliness at the point of use."

Industrial Energy Efficiency,
Office Of Technology Assessment,
Congress Of The United States.
August 1993.

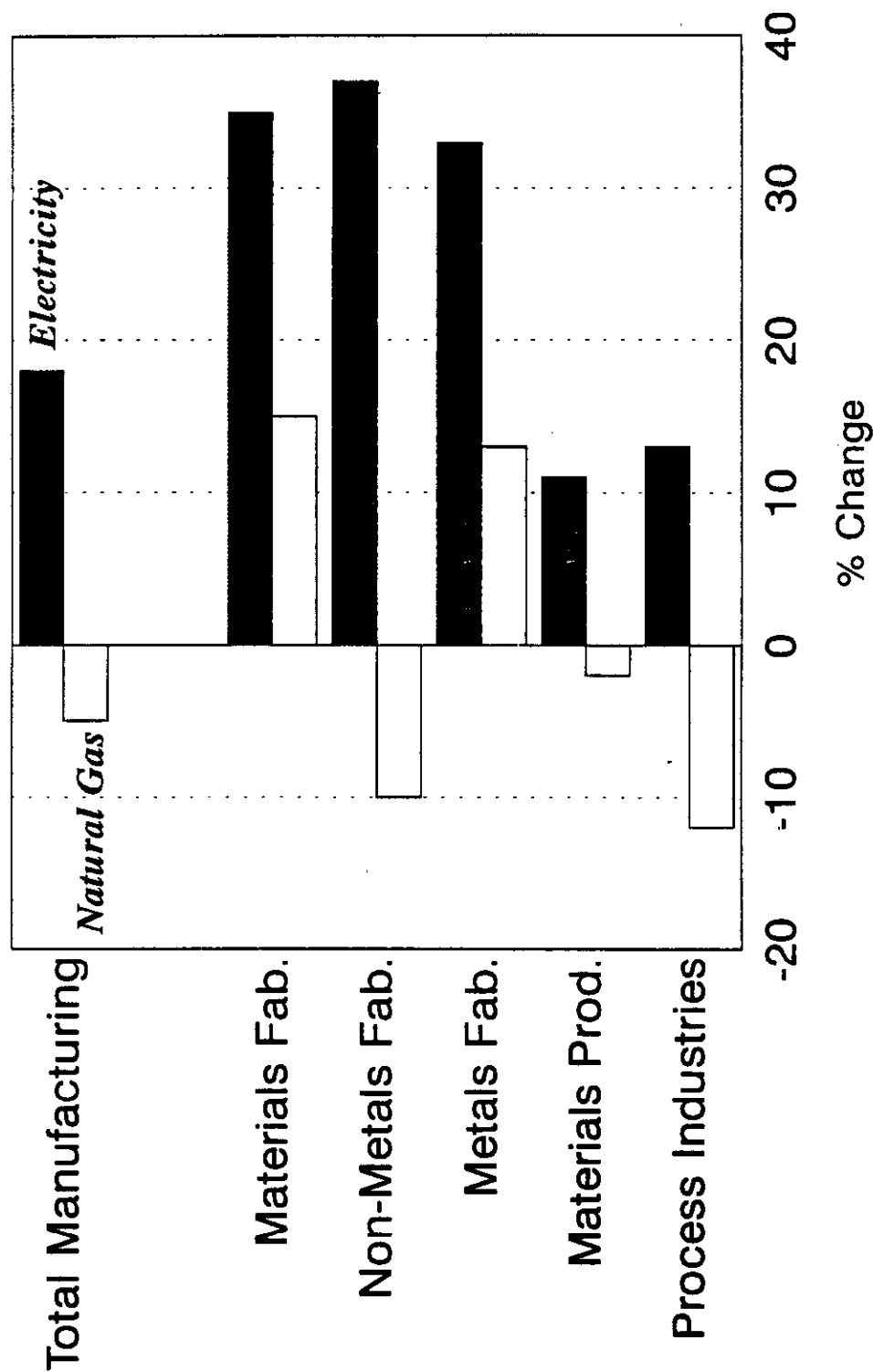
Changes In Industrial End-Use Patterns (1975-1991)



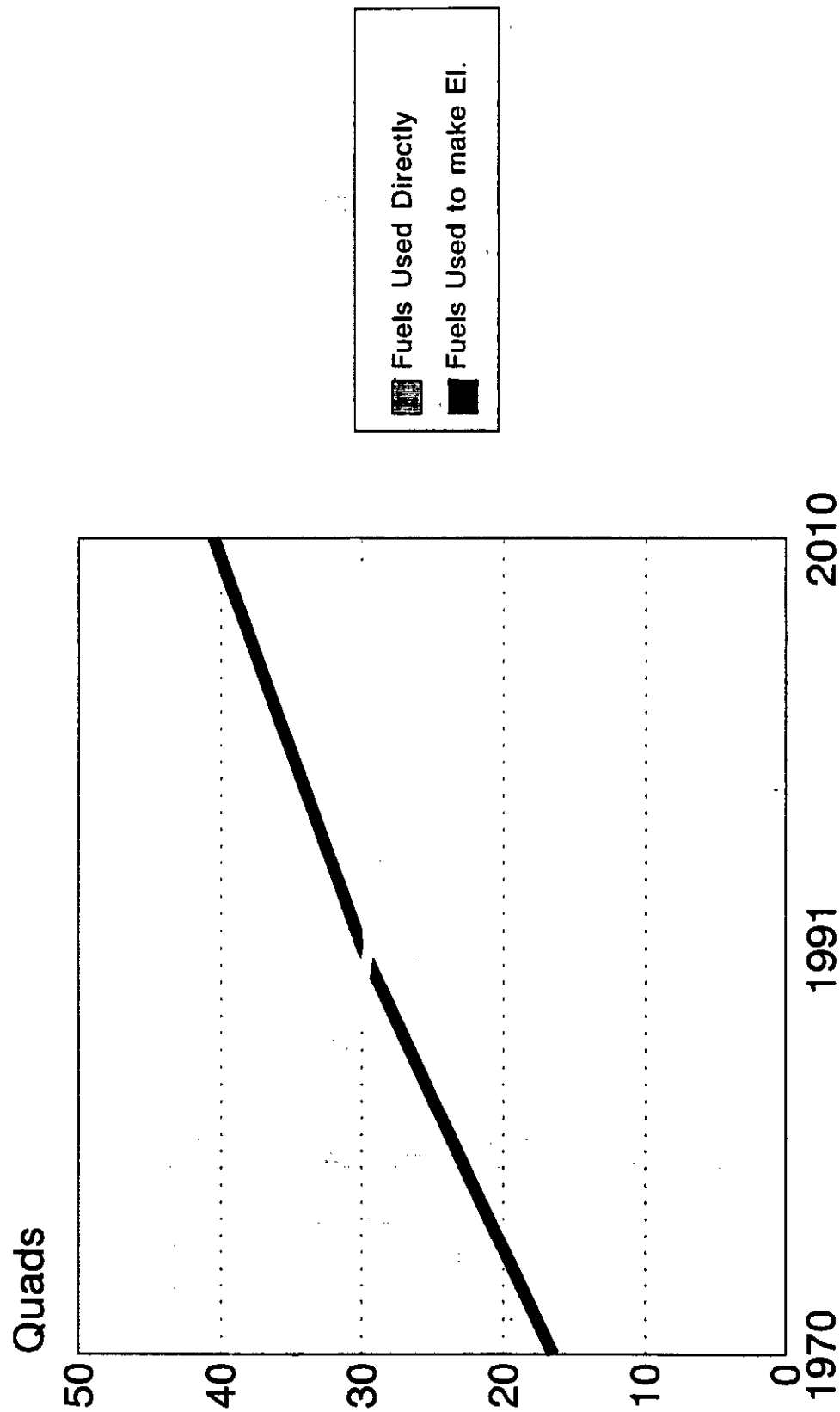
Source: U.S. DOE, EIA, Monthly Energy Review, July 1992

Change in Market Share for Fuels

Manufacturing Sector 1980-1990



Fuel Use in the Industrial+Commercial+Residential Sector



El. Electricity

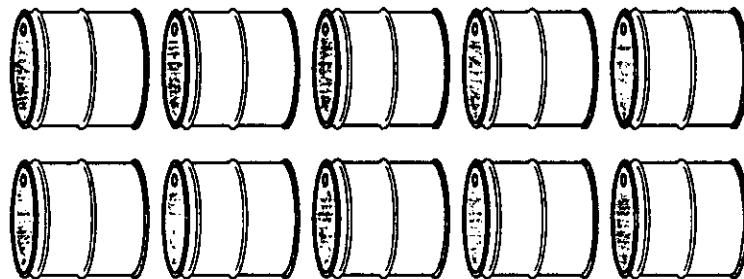
Source: Annual Energy Review, EIA, May 1991.

Electric Technologies Conserve Energy

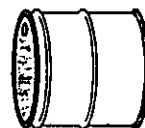
Flashbake Oven Vs. Conventional Oven

- Commercially available.
- Uses super intense visible light.
- Reduces emissions.
- Much faster.
- Much lower operating costs.

10 Energy Units



1 Energy Unit



Flashbake Oven Conventional Oven

Total Energy Consumption

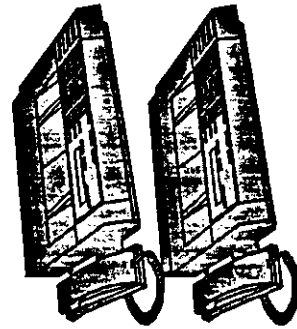
Source: Electric Council for the Economy

Electric Technologies Conserve Energy

Fax Machine vs. Overnight Delivery

- Reduces emissions.
- Quicker.
- Reliable.
- Cheaper.

2 Energy Units



10 Energy Units



Fax Machine

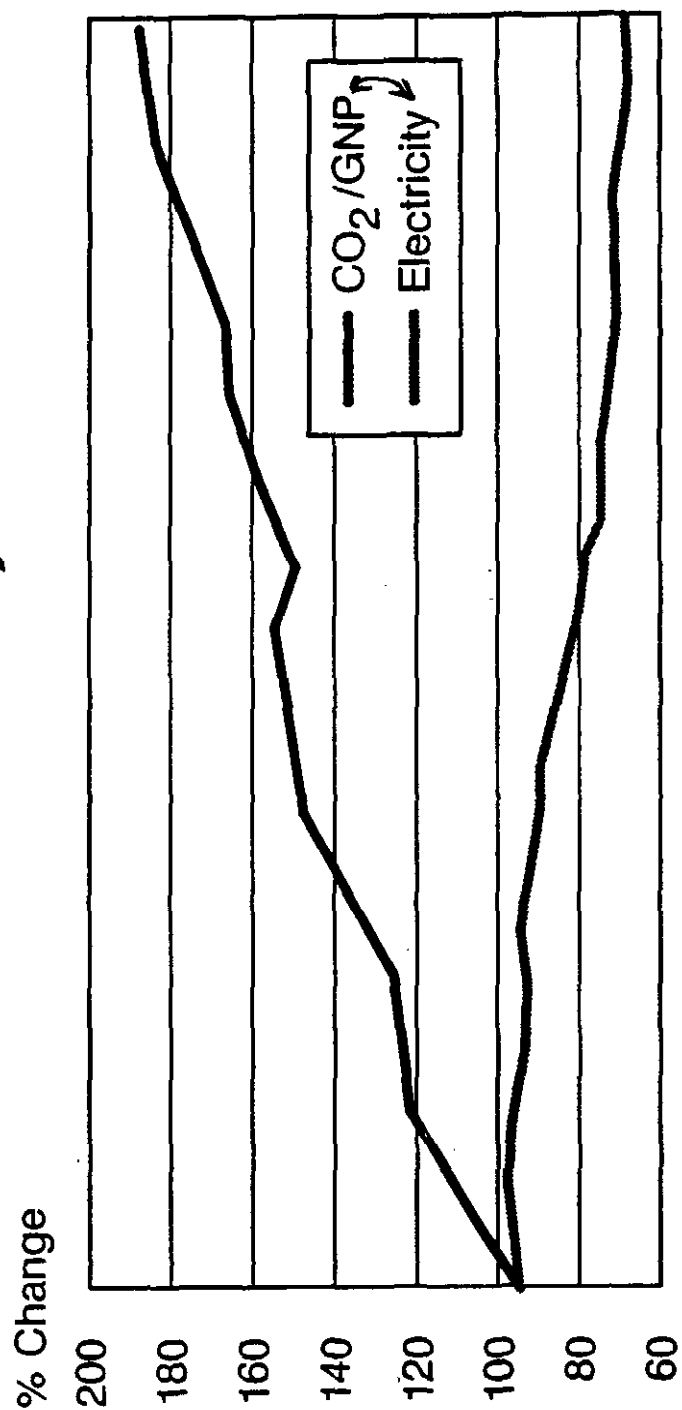
Overnight Delivery

Total Energy Consumption

Electricity's Story

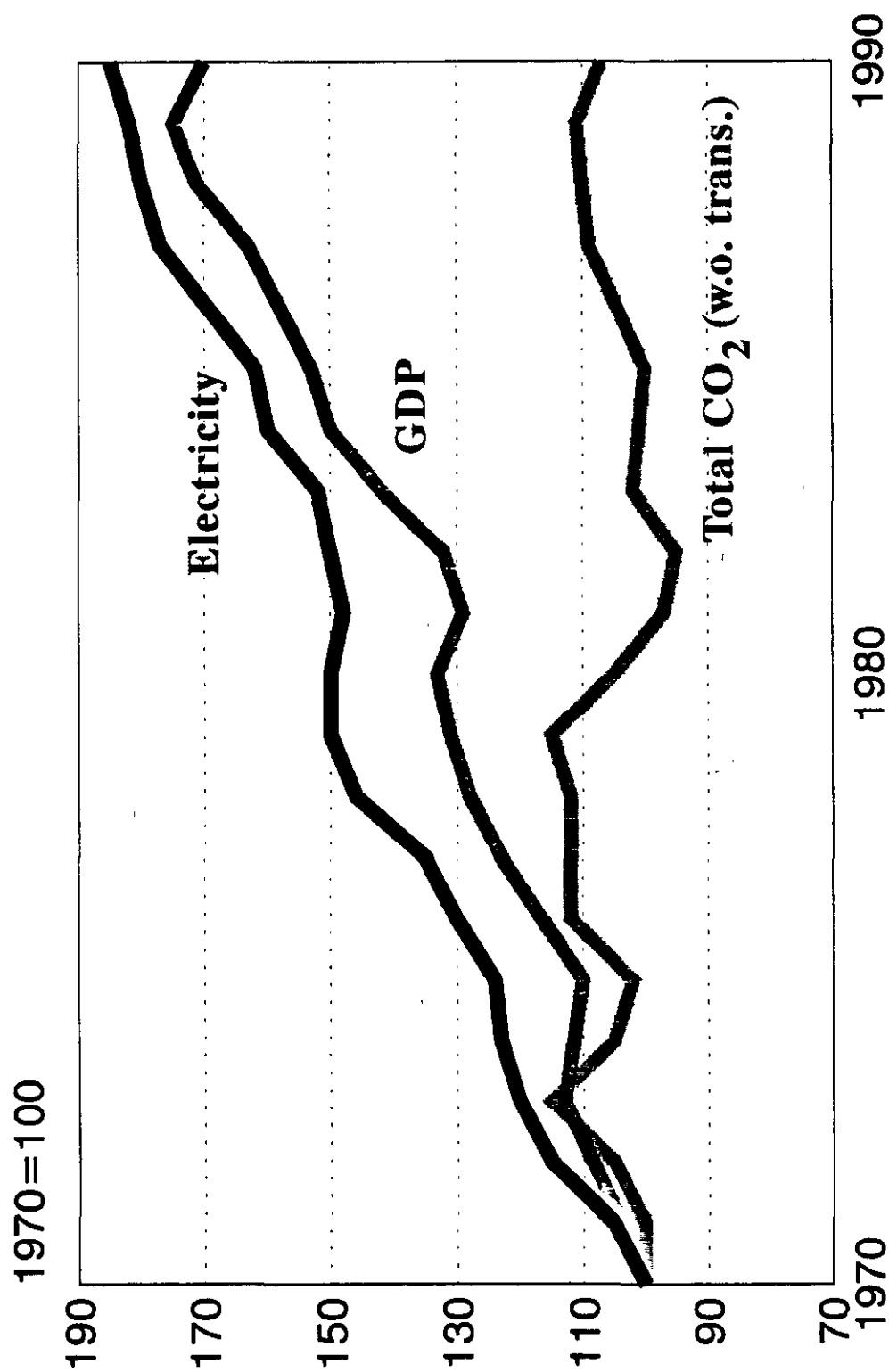
- Economic Growth
- Technology Development
- Environmental Improvement

Electricity Consumption and CO Efficiency



EEI 1993

CO₂ Emissions, Electricity Use and GDP (Excludes Transportation)



Carbon Reductions Through Electricity Substitutions

Efficient Electric Technologies vs.
Comparable Systems

Average Net Reductions In
Carbon Emissions In End Uses

Electric Arc Furnace vs. Open-hearth

or Oxygen Furnace

Infrared Heating vs. Gas Convection Oven

Electric Microwave Oven vs. Gas Oven

Induction Heating vs. Gas-fired Furnace

Electrical Glass Condition vs. Gas Furnace

Electric Melting vs. Gas Melting

Electric Chiller vs. Gas-fired Absorption

Chillers

75%

50%

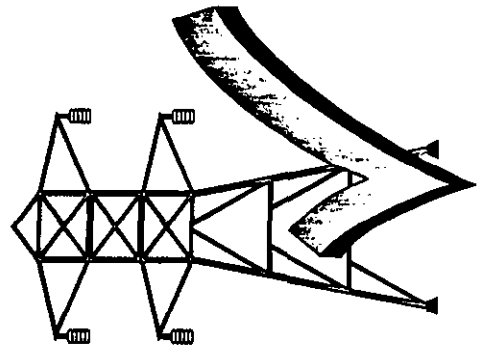
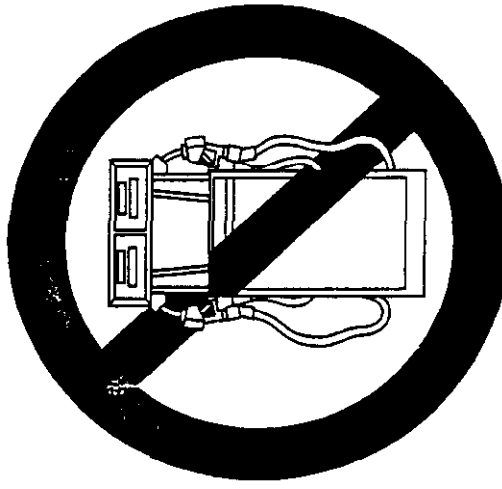
90%

35-44%

67%

8%-31%

23-31%



Carbon Reductions Through Electricity Substitutions

Efficient Electric Technologies vs. Comparable Systems	Average Net Reductions In Carbon Emissions In End Uses
--	--

Ground Source Heat Pumps vs.	
------------------------------	--

Oil Heating	48%
-------------	-----

Ground Source Heat Pumps vs.	
------------------------------	--

Gas Heating	19%
-------------	-----

Electric Fryer vs. Gas Fryer	11%
------------------------------	-----

Electric Forklift vs. Diesel Forklift	54%
---------------------------------------	-----

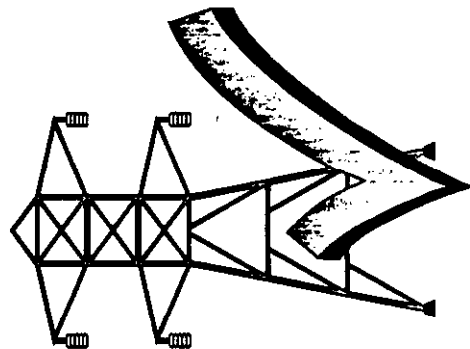
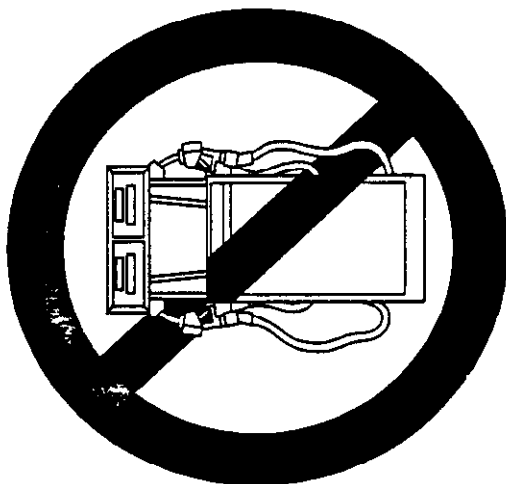
Fax Machine vs. Overnight	
---------------------------	--

Delivery Service	64%
------------------	-----

Electric Vehicle vs. Gasoline Car	43-54%
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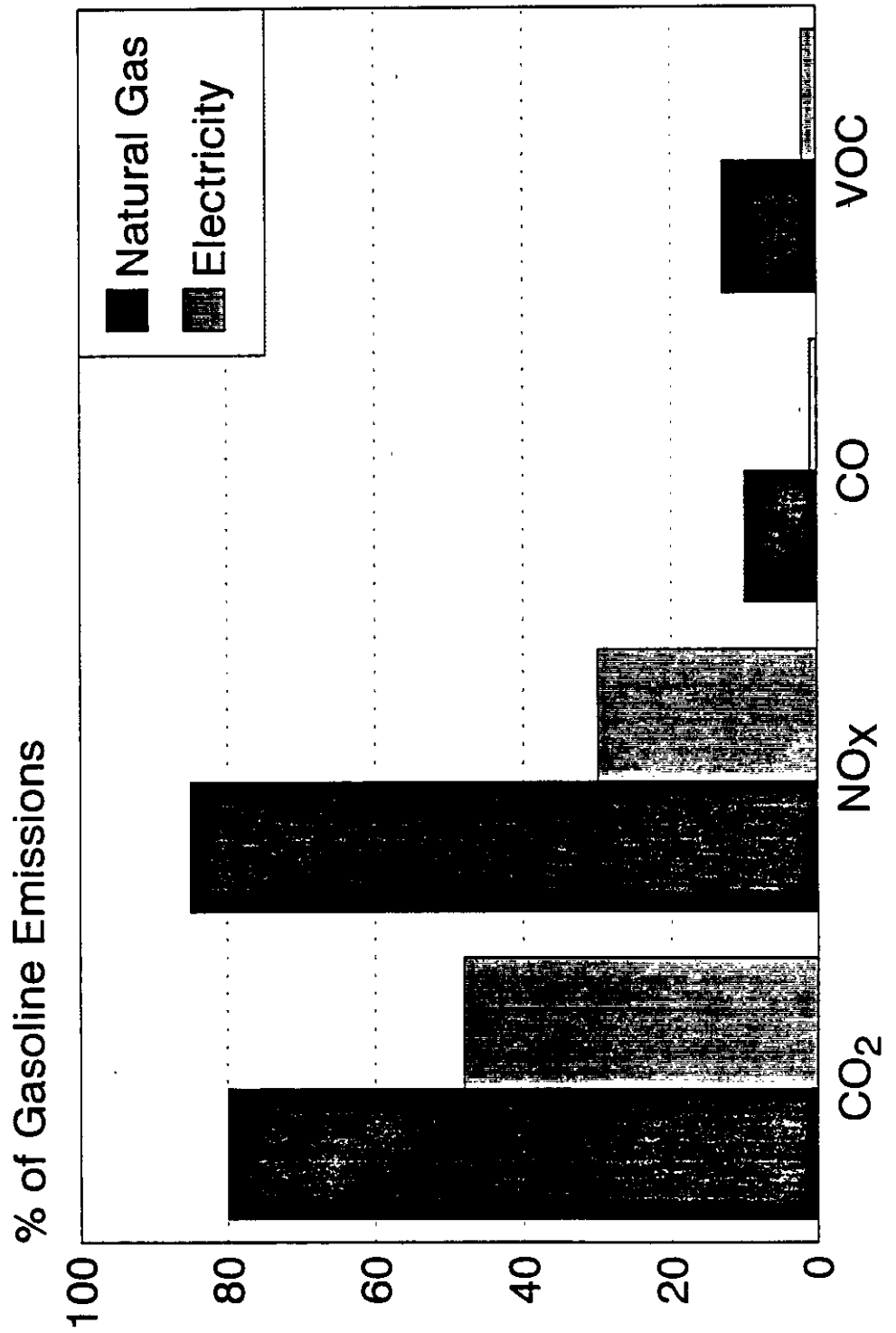
Electric Train vs. Diesel Train	14.8%
---------------------------------	-------

Electric Trolley vs. Gasoline Bus	71.8%
-----------------------------------	-------

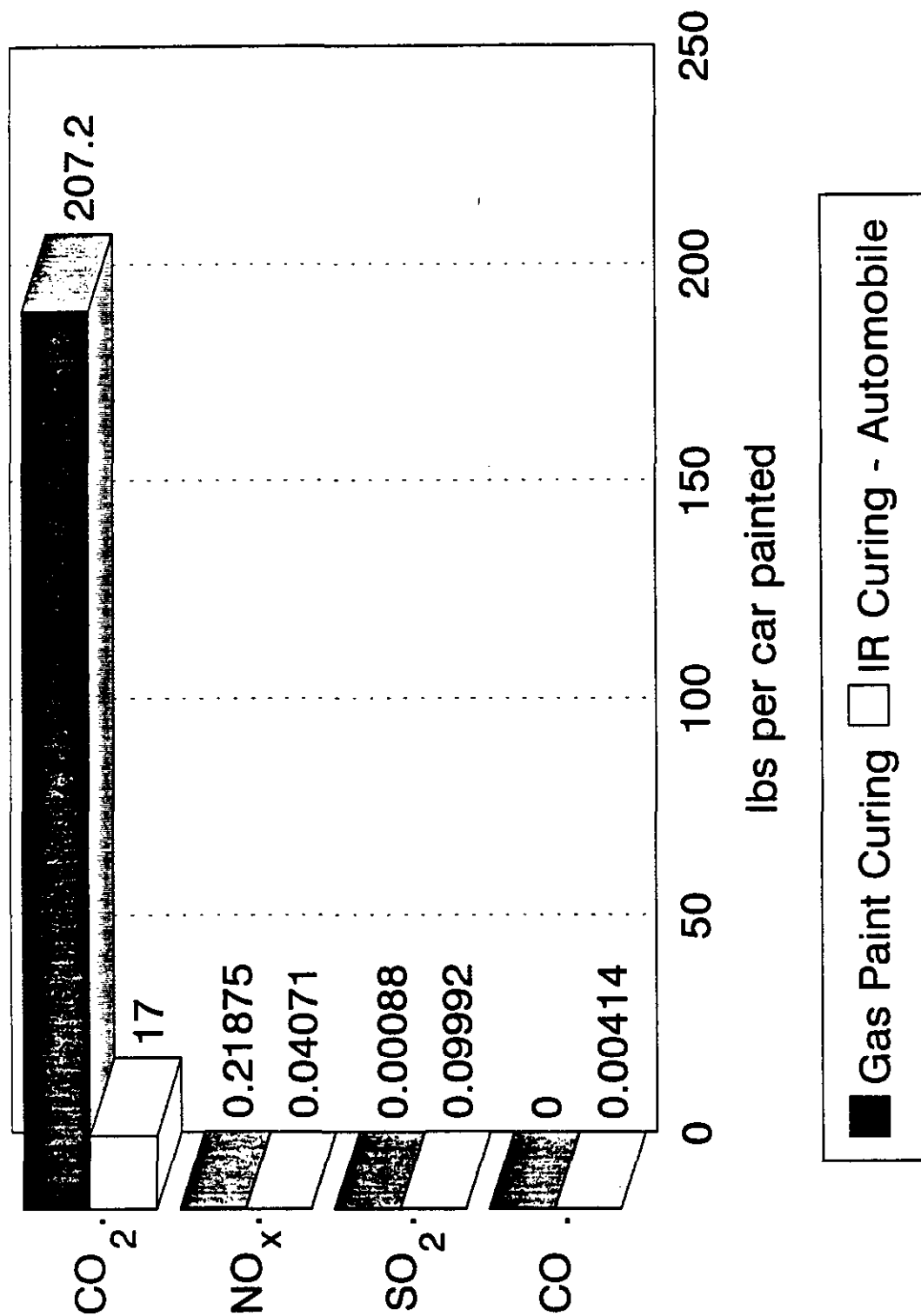


Total Fuel-Cycle Emissions - Year 2010

Compressed Natural Gas v. Electric Vehicle

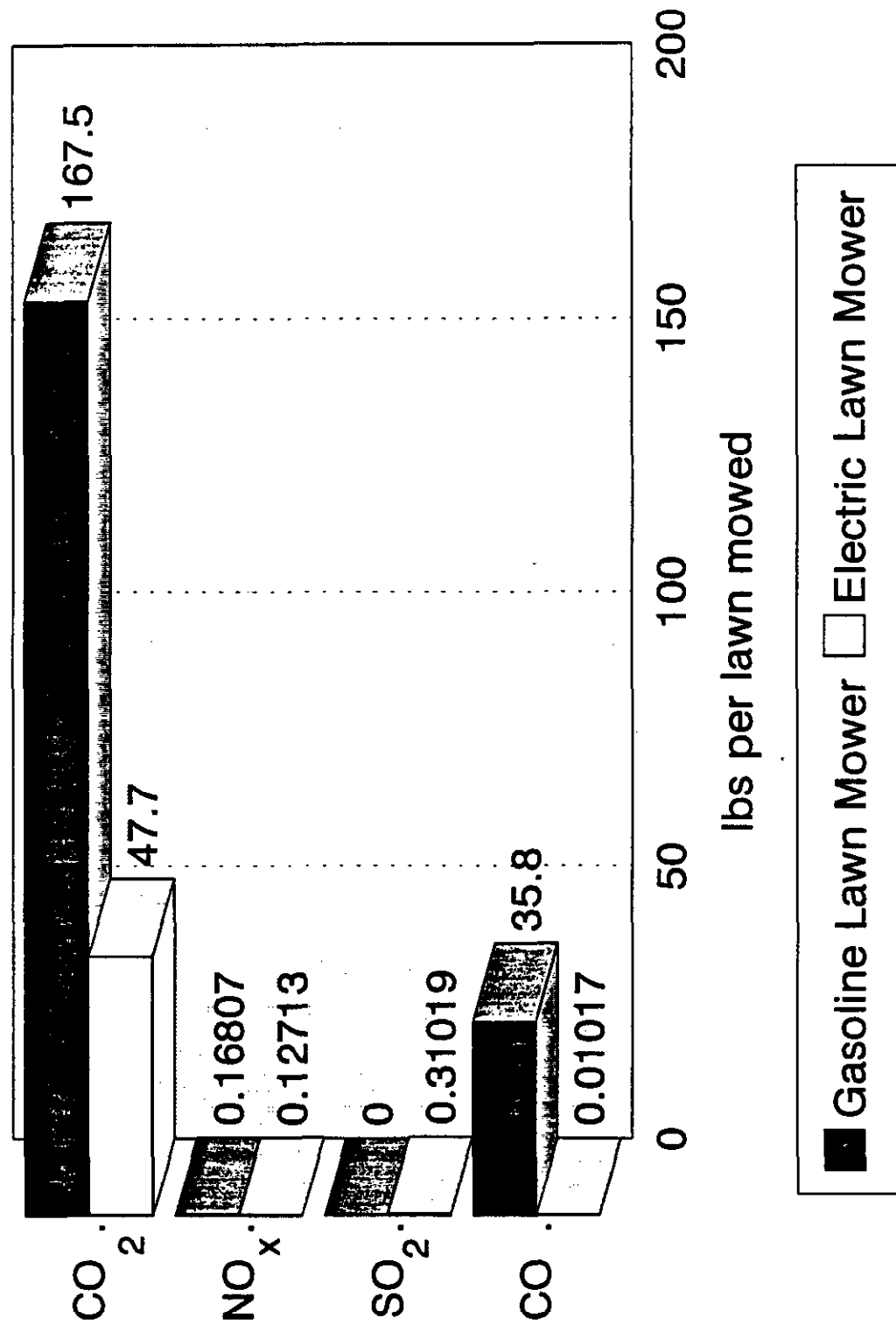


Total Emissions - Commercial Coating Application



* Preliminary data

Total Emissions - Off-Road Engines



* Preliminary data

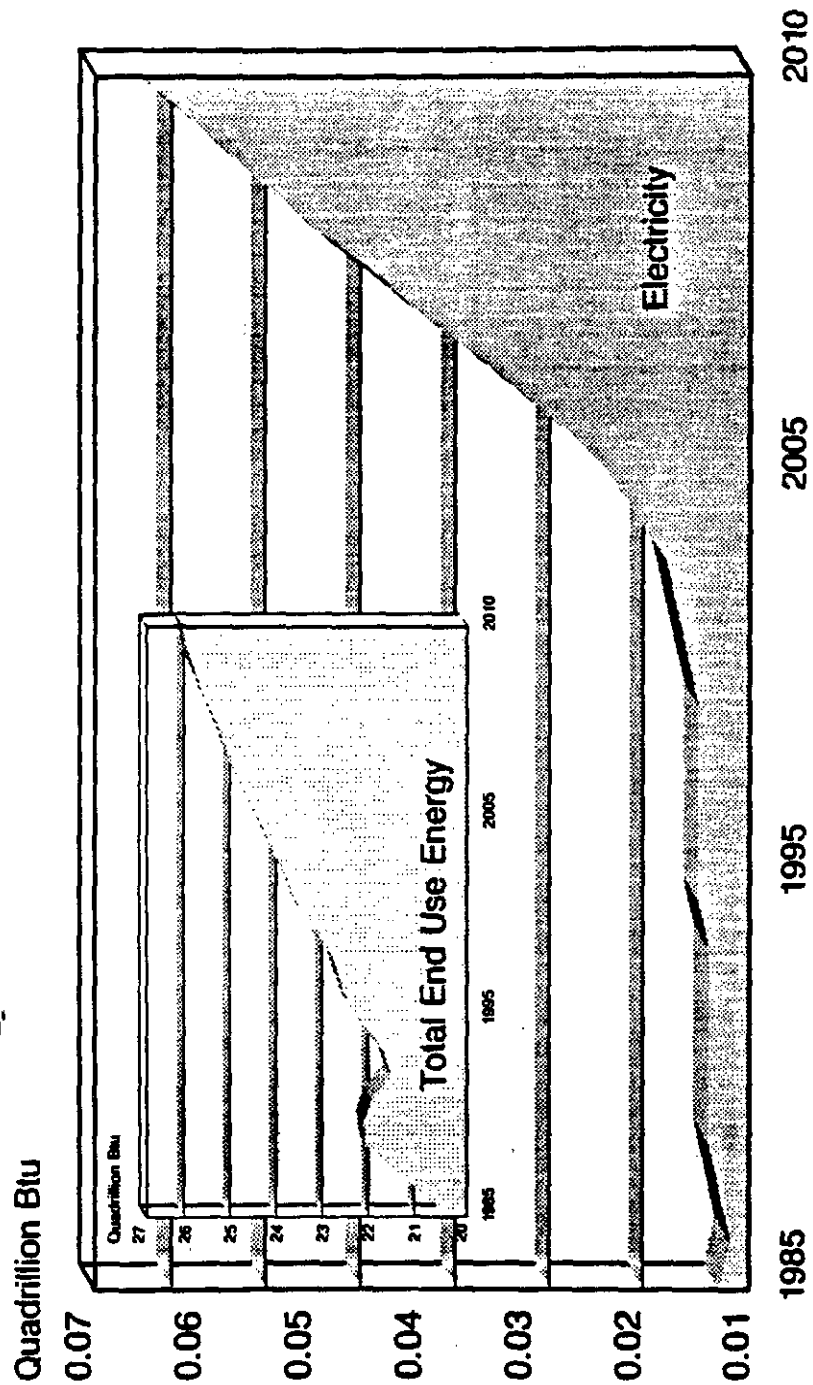
✓ Adoption

ile

Electricity and Innovation

- Preliminary Study 40,000 U.S. Patents
- Detailed Evaluation 1,158 Patents
- Electrotechnologies 30 - 40% of All Technological Innovation
 - Typically Higher Impact
 - Typically Evolve Faster
- Electrotechnologies Over 50% of Process Innovation

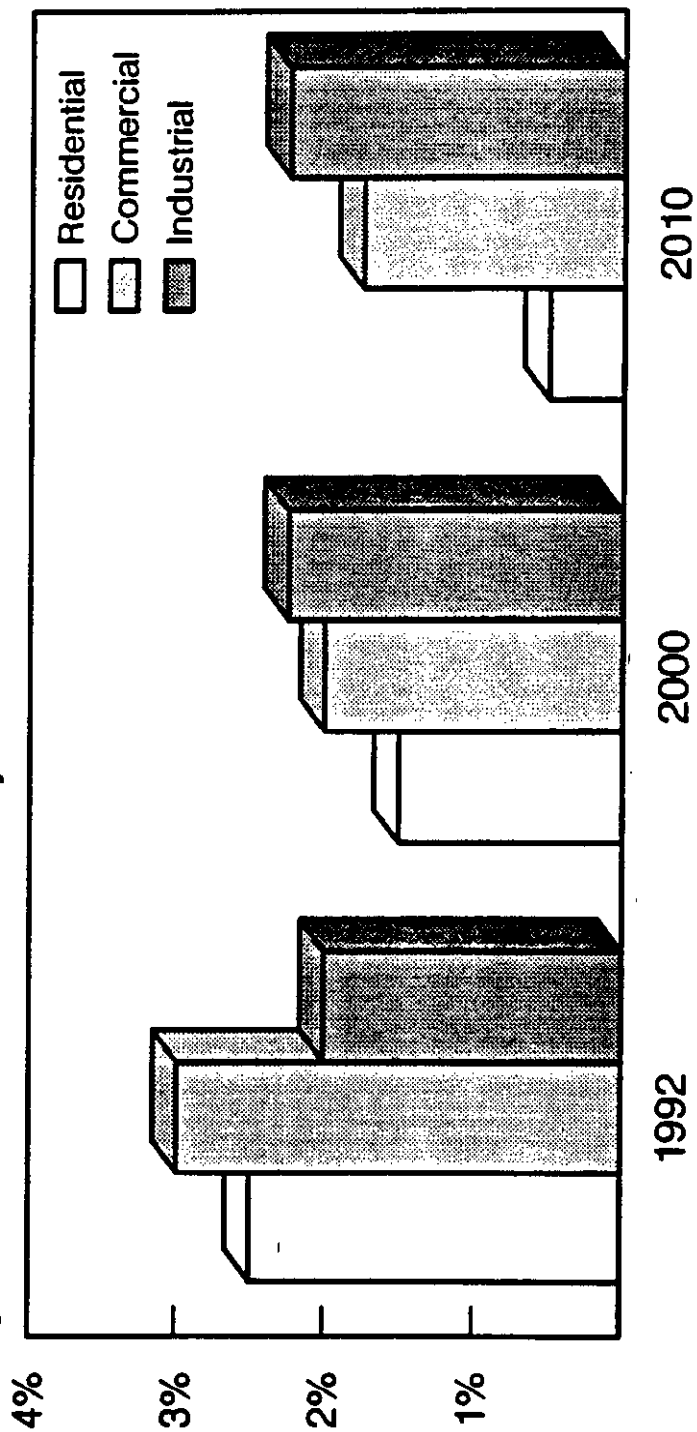
Energy Use in Transportation



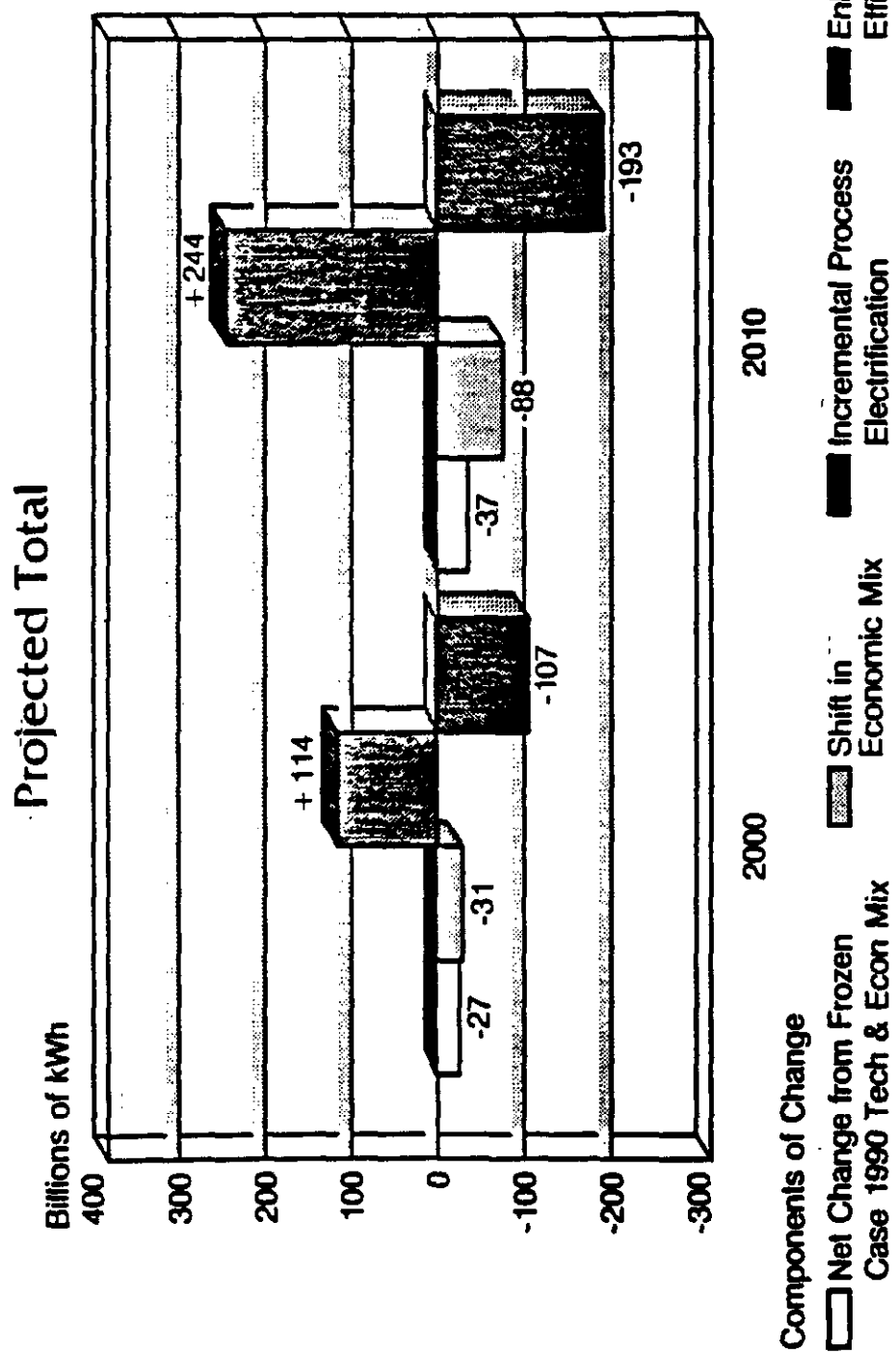
Electric Technologies: Taking America Into the Future

Industrial Sector Will Drive Future Electricity Growth

% Avg. Annual Growth in Electricity Use

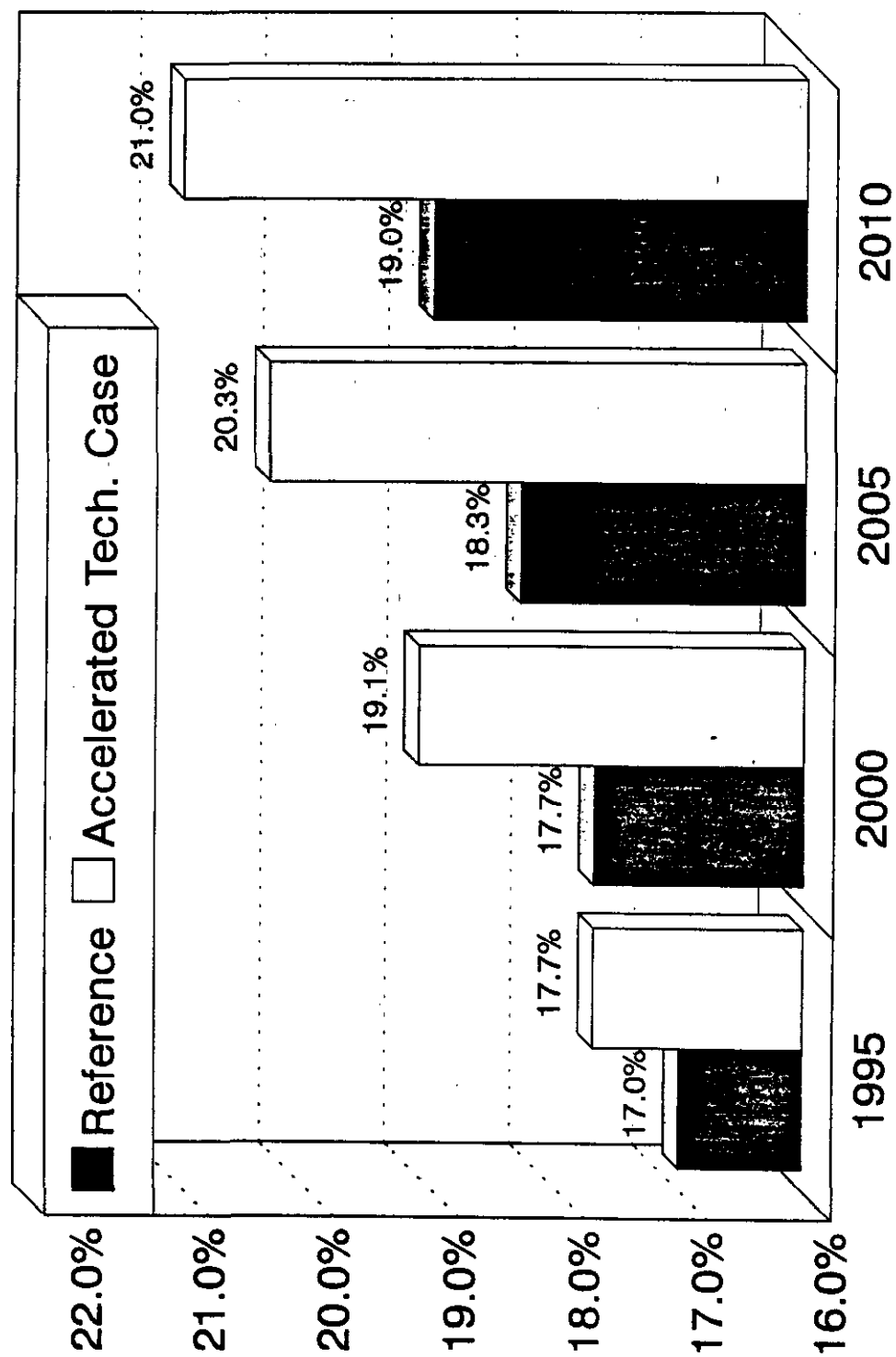


Key Trends Impacting Industrial Electricity Use



Electricity Share of Total End-Use Energy

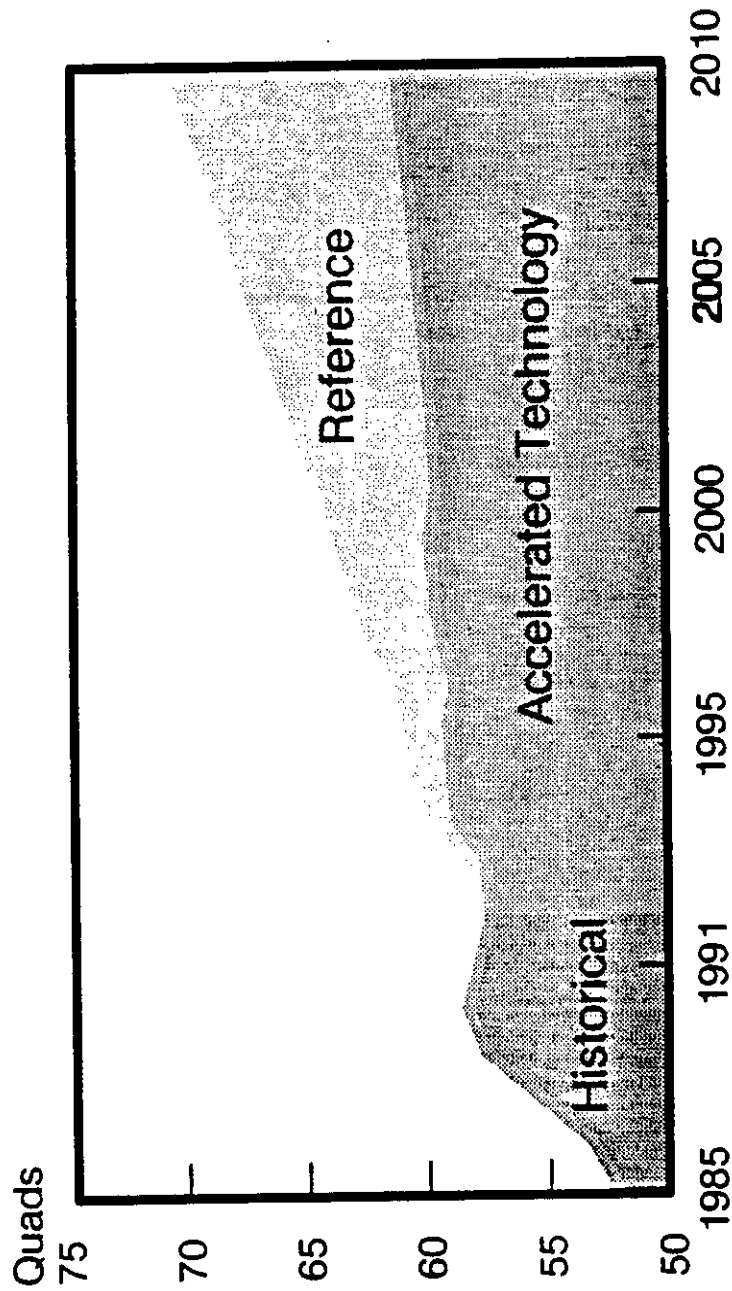
Reference and Accelerated Technology Cases



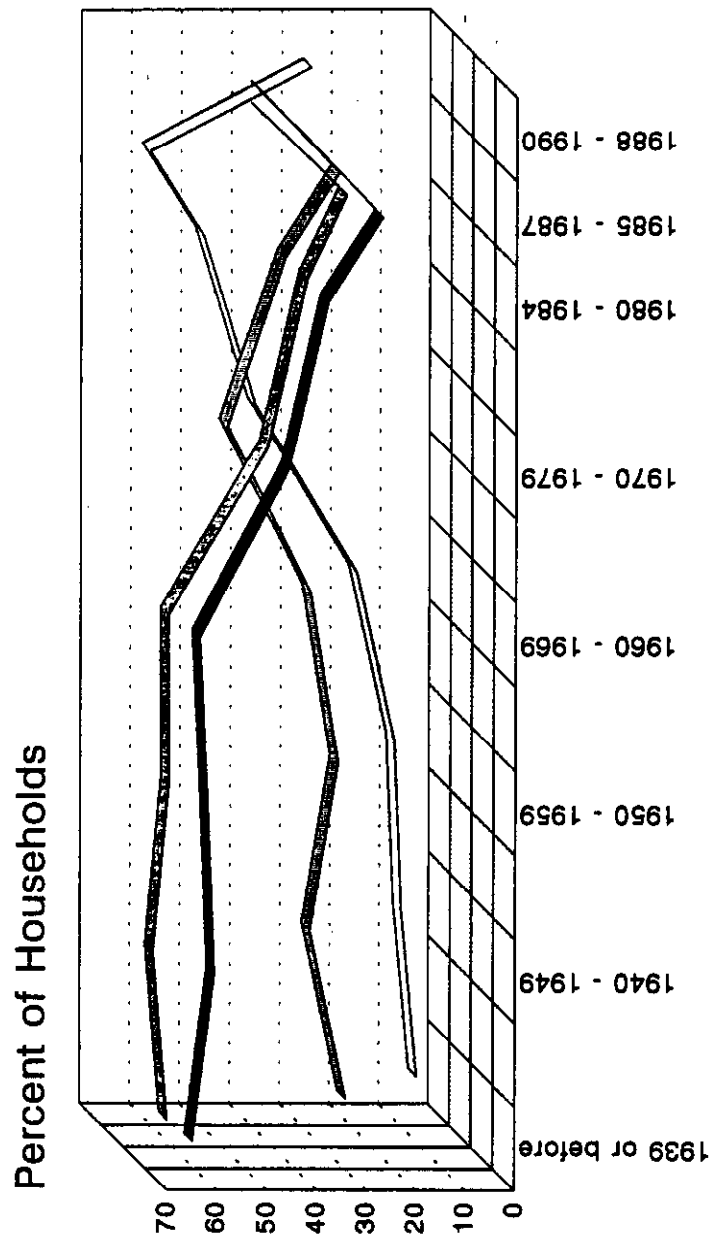
Electric Technologies: Taking America Into the Future

End-Use Energy Totals

Reference and Accelerated Technology Cases



Use of Electricity and Natural Gas for Main Space and Water Heating in U.S. Households by Year of Construction, 1990 (Percent of Households)



	1939 or before	1940 - 1949	1950 - 1959	1960 - 1969	1970 - 1979	1980 - 1984	1985 - 1987	1988 - 1990
Natural Gas Water	63.5	59.1	60.5	62.1	44.5	36.6	25.7	41.9
Natural Gas Main Space	64.2	67.1	64.	64.1	44.4	36.6	28.6	46.2
Electric Water	24.1	31.4	25.8	31.3	48	36.6	25.7	41.9
Electric Main Space	5.4	8.6	10.1	17.7	38.1	48.4	59.2	27.1

Year of Construction

Source: DOE/EIA-0314(90), p.13

Residential Sector

Causes Of The Efficiency Gap

- Lack of information
- Uncertainty about fuel prices
- Uncertainty about investment benefits (i.e. equipment performance)
- Misplaced managerial incentives
- Equipment supply infrastructure problems

Source: Industrial Energy Efficiency, Office of Technology Assessment, US Congress

Accelerated Technology Adoption

Utility Barriers

- Cost Effectiveness Tests Exclude Productivity Benefits
- State Laws & Regulations
- Prudence Issues
- Promotional Practices & Load Building Restrictions
- Economic Development & Customer Retention

Industry Changes

- Capacity Margins Down
- Generating Construction Up
(\$25 - \$30 Billion/Year)
- T&D Construction Also
- NUGs Up
- Transmission Access
- Downsizing

Overview of Industry Direction

Regulation	➡	Competition
Economic Reg.	➡	Envir. and Social Reg.
Cost Pricing	➡	Market Pricing
Supply Orientation	➡	Demand Orientation
Cost Alloc. by Reg.	➡	Cost Alloc. by Mgt. (by Market Segment)

Overview of Industry Direction (Cont'd)

Strict Oblig. to Serve	➡	Eval. of Impact on Stakeholders
Reliability Obligation	➡	Negotiated Reliability
Vertical Integration	➡	Cost Division (G, T, & D)
Need-Based Resource Allocation	➡	Profit-Based Resource Allocation
Cost Centers Managed to Budget	➡	Profit Centers Guided by Performance

The Pleased Customer...

doesn't often gush about it...Only rarely do we receive an embossed resolution of thanks...Very rarely.

But then, we don't expect it.

We are not selling "kilowatts,"

so of course can't complain about the size, the color, or the fact that we could not fill your last order and you were kept waiting a long time.

We are selling electric service -

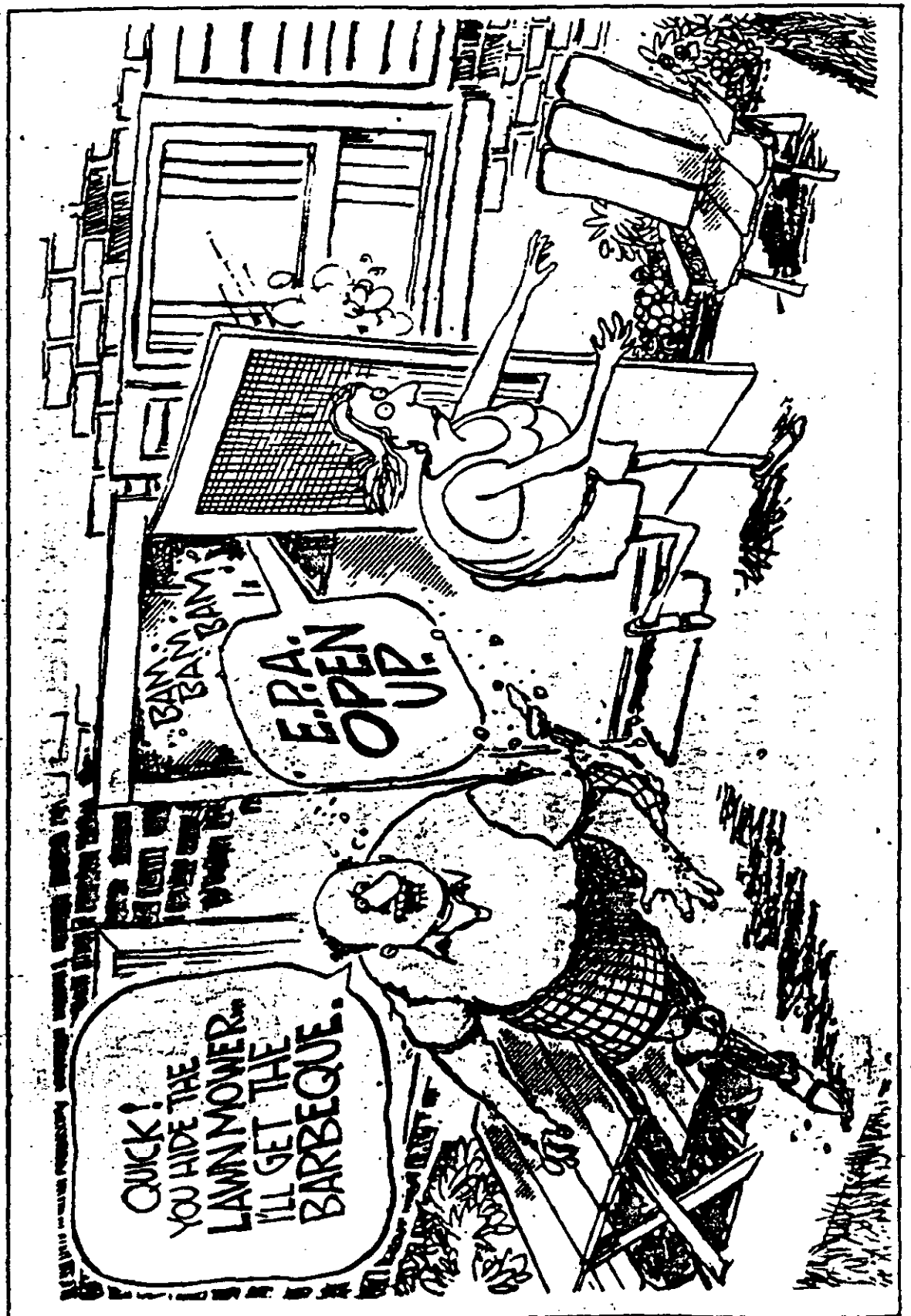
the mere flick of a switch and it does your bidding, no matter what the task, no matter at what hour of the day or night. Whether it is the family wash or the moving of a great trans-continental train; the cleaning of a rug, or turning the wheels of some gigantic factory; the lighting of the individual home, or the lighting of the whole city, electricity is ready to do its part.

We believe we are furnishing the best, the most dependable service it is humanly possible to render, at the lowest cost consistent with good business policy. But we are human and liable to make mistakes.

• So -- If you are not one of our *pleased* customers, tell us about it.

Name of Light & Power Co.

CITY AND STATE ADDRESS



CLEAN COAL TECHNOLOGIES
AND
GLOBAL CLIMATE CHANGE

Speech by
Robert S. Long
Vice President, Government Affairs
National Coal Association
and Chairman of Operating Committee
Global Climate Coalition

to

Second Annual Clean Coal Technology Conference
September 9, 1993

I. Introduction

Good afternoon ladies and gentlemen. I am Robert Long, with the National Coal Association (NCA), and I also serve as Chairman of the Operating Committee of the Global Climate Coalition (GCC). GCC is a broad-based organization with over 50 companies and trade associations, formed to represent business interests in the global climate issue. Our members include oil, gas, coal, utilities, autos, steel, aluminum, chemicals, railroads, forest products and cement. I will be discussing the role for Clean Coal Technologies in the context of the global climate change debate.

Global climate change is, of course as the name implies, a global issue. This clearly distinguishes this issue from acid rain or ozone non-attainment, which are regional in nature. Therefore, the issue requires a global perspective, one that looks at the issue not just from a U.S. policy standpoint but from an international policy view. This includes the positions of other individual nations, trading blocs, common interest groups, and the evolving United Nations bureaucracy.

To begin examining this big picture, we take as a given the assumption that as the global economy continues to grow, energy demand will also grow. With growth in economic activity and energy use, will come growth in worldwide greenhouse gas emissions, including growth in Carbon Dioxide (CO₂) emissions. Much of this growth will occur in developing economies which intend to fuel their growth with coal-fired power, especially China and India.

Next, let me give you two basic premises which set out the boundaries of this topic. First, there is the premise that global climate change is occurring, or is about to occur, and that governments must do something to mitigate the causes of climate change. This is the principle behind the Climate Treaty, which I will discuss in a moment. Although this premise is highly rebuttable, and not based on scientific certainty, political science has driven it to the forefront of the debate. Second is the premise that advanced combustion CCT's, with their higher efficiencies, will result in lower CO₂ emissions, and hence lessen any contribution of greater coal use to potential global climate change. This premise is demonstrably true.

Within this context, this discussion will focus on recent and emerging public sector policy actions, which may in large part establish a new framework in which the private sector will find new challenges and new opportunities.

II. The United Nations Framework Convention on Climate Change

Global climate change is not a new issue on the international scene. Formal international negotiations, under United Nations (U.N.) auspices, began in February 1990. These negotiations, steered by the U.N. Intergovernmental Negotiating Committee (Intergovernmental Negotiating Committee), ultimately lead to the U.N. Framework Convention on Climate Change (FCCC), or Climate Treaty for short. This is the document which then-President George Bush signed in Rio de Janeiro in June 1992. Since it is a Treaty, the document then went to the U.S. Senate, which ratified it in October 1992.

Much of the attention on the Treaty was focused on Article 4, the Commitments section of the document. This is the section that establishes the aim of developed country Parties to the Treaty to return to 1990 levels of greenhouse gas emissions by the year 2000. Note that this is defined in the Treaty as an aim, and not a binding commitment. However, Article 2 of the Treaty, which establishes the objective, speaks in terms of "stabilization of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system." Although this is not a binding commitment either, increasing reference is made to this objective in the ongoing international debate over implementation of the Treaty.

Although the Treaty has been signed and ratified by the U.S., it has not yet entered into force. Entry into force will not occur until 90 days after 50 nations have ratified the Treaty. We currently expect that this may occur in early 1994, or perhaps even by the end of this year. In the interim, there are many as-yet unanswered questions about how the Treaty will be implemented by its various Parties. Those questions are now being debated by the Intergovernmental Negotiating Committee, which will continue in existence until the Treaty enters into force, after which a Conference of the Parties will be created as the new governing body to administer the Treaty.

The Bush Administration, which successfully resisted firm emission reduction targets and timetables in the Treaty, had however, chosen to emphasize the need for a "prompt start" to implementing the Treaty on a voluntary basis. To this end, they produced and published in the Federal Register a proposed U.S. National Action Plan (NAP) in December 1992. Many organizations, including NCA and GCC provided comments on this proposed plan. National action plans are the vehicle by which Parties to the Treaty will communicate to the Conference of the Parties how they plan to implement the Treaty.

The Clinton Administration chose to up the ante on Treaty implementation somewhat. In his Earth Day Speech in April of this year, President Clinton announced his personal and our national commitment to return to 1990 levels of greenhouse gas emissions by 2000. While this also may not be a legally binding commitment, it is a step in that direction, and in diplomatic terms, a strong signal to other Parties of a shift in U.S. policy. President Clinton also announced in the same speech his intention to have a revised U.S. National Action Plan ready in time for the just-completed eighth session of the Intergovernmental Negotiating Committee, held in Geneva, Switzerland, August 16 - 27. For a number of reasons, including vigorous lobbying by the business community, the Administration found it could not hold to this schedule. The Administration now plans to issue a revised plan sometime this fall.

III. Joint Implementation

This brings me to one of the most hotly debated topics at the Intergovernmental Negotiating Committee meeting, and within the Administration, and which is most relevant to this discussion. This is the topic of joint implementation of the Treaty. This concept grew out of a recognition, by some of the developed country Parties during the negotiations leading up to the Treaty, that they might have great difficulty in attaining the aim of the Treaty solely through internal, domestic actions. This led to language in the Treaty that creates the opportunity for Parties to the Treaty to implement climate mitigation measures jointly with other Parties.

This concept is still not well-defined, and as I mentioned earlier, is still the subject of strong debate within the Intergovernmental Negotiating Committee. However, it is generally understood to mean that one Party could sponsor a project in another host Party, and receive credit for emissions reductions achieved. Projects are generally thought to span a wide range, and to include projects to enhance greenhouse gas sinks, such as reforestation and afforestation projects, as well as greenhouse gas emission reduction projects, such as energy efficiency projects, and other industrial process applications. This presents an opportunity to comply with the Treaty by obtaining reductions where it is easiest and most cost-effective to do so in developing countries.

The debate on joint implementation is far from being resolved, since the international community is seriously split on the issue. Developing countries, as represented by a loose affiliation known as the Group of 77, are split on the issue. Some have expressed great skepticism about joint implementation. Many in this camp seem to see it only as a means by which developed countries could circumvent their commitments under the Treaty. Or, worse still, is the view expressed by the head of the delegation of Argentina, who is also Chairman of the Intergovernmental Negotiating Committee, that joint implementation may be merely a stalking horse to allow developed countries to practice some sort of "environmental colonialism" on hapless and unsuspecting developing country partners. Others, such as Mexico, see it as a very positive force, which can bring new partners and new resources to their efforts to develop.

Developed countries, for their part, are also split. The European Community (EC), when speaking with its official interest bloc voice, is opposed to joint implementation between developed countries and developing countries. They maintain that joint implementation should be allowed between developed countries only. However, not all members of the EC are in full agreement with this position.

Other developed countries, including the U.S., Canada, Australia, New Zealand and Japan, maintain that joint implementation should be available to and between all Parties to the Treaty. They point out that joint implementation represents a means, and here is the key for this audience, to involve the private sector, and to increase the flow of resources available to developing countries for climate change mitigation projects.

The U.S. statement on joint implementation to the Intergovernmental Negotiating Committee was particularly interesting, especially since there were some factions within the Administration who were opposed to including it at all. The U.S. did endorse joint implementation, with some qualifications.

1. Legal Issues

In terms of legal issues, the U.S. believes that joint implementation is available as a measure between all Parties. Further, the U.S. maintains that joint implementation is available to developed countries in the context of meeting their commitment to reach 1990 levels by the year 2000. In other words, it can be an element of our national action plan.

2. Criteria

As far as criteria for joint implementation, the U.S. put forward several suggestions. Joint implementation should be voluntary; it should consist of mutually voluntary projects between partners, aimed at reducing net emissions of greenhouse gases, and could be agreed to by governments of participating countries.

Joint implementation should embody additionality. That is, it should incorporate commitments and projects above a certain baseline level, to ensure that real reductions occur.

Verifiable reductions should be required; a system should be developed in which emissions are monitored to ensure that projected reductions are achieved.

Joint implementation should incorporate a diverse system of projects; a wide range of projects should be encouraged, including energy projects and agricultural projects, as well as projects having to do with greenhouse gas sinks.

3. Overall Context

The U.S. sees joint implementation as leading to a program which can significantly increase the flow of resources between participants. This would include technology transfer and increase in technology cooperation. There are only limited global resources available to take mitigation measures, and joint implementation offers the potential to use those resources as wisely and efficiently as possible.

IV. Global Climate Coalition Position

The Global Climate Coalition, has consistently and strongly supported technology cooperation, as part of a rational approach to the question of potential global climate change. We recognize that there are still considerable impediments to broad-scale technology cooperation efforts, and that to be successful on a broad-scale such efforts should be on a private sector-to-private sector basis.

Second Annual Clean Coal Technology Conference

Robert Long

Page 7 of 7

However, the Federal government's resources can play an important role in helping industry identify opportunities for technology cooperation, and in providing market-based financing facilities for technology cooperation efforts. What we do not need is another impediment, such as closing the door on joint implementation projects. It is difficult to estimate the exact impact this might have on CCT project opportunities, but the effect most certainly would be chilling.

As I mentioned earlier, the GCC has recently lobbied the Administration and key Members of Congress, to keep joint implementation in the mix. We are gratified by the position taken by the U.S. delegation in Geneva. But the battle is not yet over, and I would suggest that all of us who have a stake in this one need to continue to express our support for keeping joint implementation an available option under the Treaty.

**REGULATORY ISSUES THAT MAY AFFECT
THE FUTURE DEVELOPMENT OF
CLEAN COAL TECHNOLOGIES**

**Craig S. Harrison, Esq.
Utility Air Regulatory Group
Hunton & Williams**

**(The comments of Mr. Harrison were not
available at the time of publication.)**

Appendix A

List of Attendees

Second Annual Clean Coal Technology Conference List of Attendees

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Maurice Alphandary
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Zoltan Barocsi
Hungary

C.A. (Chuck) Bayens
President
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Second Annual Clean Coal Technology Conference List of Attendees

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Chris B. Bellringer
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Charles Bliss
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Second Annual Clean Coal Technology Conference List of Attendees

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Appendix B

Conference Schedule

**Wednesday
September 8, 1993**

**Thursday
September 9, 1993**

7:30 a.m.	Speakers' Breakfast, Paulding Room Continental Breakfast, Grand Salon East 7:30-9:00			
8:00 a.m.				
9:00 a.m.				
10:00 a.m.	Plenary Session 1 Ballroom East 9:00-12:00 5 Speakers			
11:00 a.m.				
12:00 p.m.	Luncheon Grand Salon East 12:00-1:30 Speaker			
1:30 p.m.	Clean Coal Technology Markets Session Rockdale/Forsythe 1:30-3:00 Break 3:00-3:20	Session 1 NO_x Control Technologies Ballroom A 1:30-3:00 Break 3:00-3:20	Session 2 Advanced Elec. Power Gen. Systems Ballroom B 1:30-3:00 Break 3:00-3:20	Session 3 SO₂ Control Technologies Fayette/Newton 1:30-3:00 Break 3:00-3:20
3:00 p.m.	Clean Coal Technology Markets (cont.) Rockdale/Forsythe 3:20-5:00 7 papers	NO_x Control Technologies (cont.) Ballroom A 3:20-5:00 6 papers	Session 4 Industrial Applications Ballroom B 3:20-5:00 4 papers	SO₂ Control Technologies (cont.) Fayette/Newton 3:20-5:00 5 papers
4:00 p.m.	Plenary Session 2 Emerging Issues/Environmental Ballroom East 1:30-4:00 6 Speakers			
5:00 p.m.				